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BEFORE THE ARIZONA CORPORATION COMMISSION

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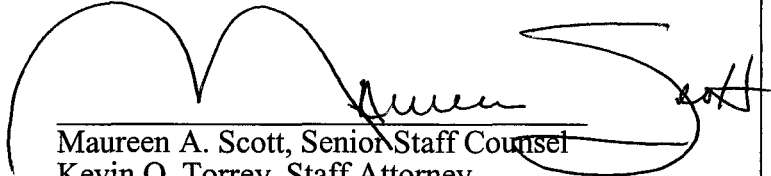
IN THE MATTER OF THE APPLICATION OF
SOUTHWEST GAS CORPORATION FOR
THE ESTABLISHMENT OF JUST AND
REASONABLE RATES AND CHARGES
DESIGNED TO REALIZE A REASONABLE
RATE OF RETURN ON THE FAIR VALUE
OF ITS PROPERTIES THROUGHOUT
ARIZONA.

DOCKET NO. G-01551A-07-0504

STAFF'S NOTICE OF FILING OF DIRECT
TESTIMONY

The Utilities Division ("Staff") hereby provides Notice of Filing of the redacted Direct
Testimony of Ralph C. Smith; and the Direct Testimonies of Corky Hanson; Frank W. Radigan;
David C. Parcell; Phillip S. Teumim; Robert G. Gray; Rita R. Beale; and Stephen L. Thumb.

RESPECTFULLY SUBMITTED this 28th day of March, 2008.


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Original and thirteen (13) copies
of the foregoing filed this
28th day of March 2008 with:

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Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Arizona Corporation Commission
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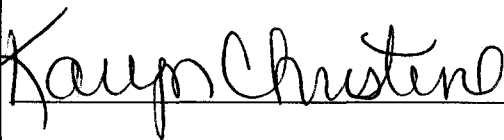
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DIRECT

TESTIMONY

OF

RALPH C. SMITH

CORKY HANSON

FRANK W. RADIGAN

DAVID C. PARCELL

PHILLIP S. TEUMIM

ROBERT G. GRAY

RITA R. BEALE

STEPHEN L. THUMB

DOCKET NO. G-01551A-07-0504

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SOUTHWEST GAS CORPORATION FOR THE
ESTABLISHMENT OF JUST AND
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DESIGNED TO REALIZE A REASONABLE
RATE OF RETURN ON THE FAIR VALUE OF
THE PROPERTIES OF SOUTHWEST GAS
CORPORATION DEVOTED TO ITS
OPERATIONS THROUGHOUT ARIZONA**

MARCH 28, 2008

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON

Chairman

WILLIAM A. MUNDELL

Commissioner

JEFF HATCH-MILLER

Commissioner

KRISTIN K. MAYES

Commissioner

GARY PIERCE

Commissioner

IN THE MATTER OF THE APPLICATION OF)
SOUTHWEST GAS CORPORATION)
FOR JUST AND REASONABLE)
RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF SOUTHWEST GAS)
CORPORATION DEVOTED TO ITS)
OPERATIONS THROUGHOUT ARIZONA.)

DOCKET NO. G-01551A-07-0504

REDACTED DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

My testimony addresses the following issues, and responds to the testimony of Southwest Gas Corporation ("Company," "Southwest," or "SWG") witnesses Montgomery, Mashas, Aldridge and Hobbs on these issues:

- The Company's proposed revenue requirement
- Adjustments to test year data
- Rate base
- Test year revenues, expenses, and net operating income

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of \$50.22 million is significantly overstated. On original cost rate base ("OCRB") my calculations show a jurisdictional revenue deficiency of \$29.57 million. I recommend that SWG be authorized a base rate increase of \$29.57 million on adjusted fair value rate base ("FVRB"). This amount is between the Staff's two options for the revenue requirement on FVRB. On adjusted FVRB under Staff's option 1, which uses a fair value rate of return of 6.80 percent, I show a base rate increase of \$29.00 million. Similar to Staff's recommendations in a recent remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City Water Company, Staff is also presenting the Commission with an option 2 for the fair value rate of return for SWG. Under option 2 the fair value rate of return for SWG is 7.09 percent, and the jurisdictional revenue deficiency is approximately \$35.71 million. The testimony of Staff witness David Parcell addresses the determination of the fair value rate of return. In its filing, Southwest calculated the same revenue deficiency under the OCRB and FVRB, and consequently has not requested an additional rate increase on FVRB. As noted above, in this case, the jurisdictional revenue deficiency of \$29.57 million falls between the two fair value options.
- The following adjustments to Southwest's proposed original cost rate base should be made:

Summary of Staff Adjustments to Rate Base		OCRB	RCND RB
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-1	Yuma Manors Pipe Replacement	\$ (1,092,448)	\$ (1,092,448)
B-2	Customer Advances for Construction	\$ (7,399,425)	\$ (7,399,425)
B-3	Cash Working Capital	\$ 53,791	\$ 53,791
B-4	Customer Deposits	\$ (2,480,873)	\$ (2,480,873)
B-5	Accumulated Deferred Income Taxes - Acct.190	\$ (13,132,025)	\$ (20,109,648)
B-6	Intangible Plant Added After the Test Year	\$ (543,210)	\$ (543,210)
B-7	Accumulated Deferred Income Taxes - RCND		\$ (95,409,229)
	Total of Staff Adjustments	\$ (24,594,190)	\$ (126,981,042)
	SWGas Proposed Rate Base (Original Cost and RCND)	\$ 1,094,790,047	\$ 1,843,481,069
	Staff Proposed Rate Base (Original Cost and RCND)	\$ 1,070,195,857	\$ 1,716,500,027

- The following adjustments to Southwest's proposed revenues, expenses and net operating income should be made:

Summary of Staff Adjustments to Net Operating Income		Pre-Tax Adj. to Revenue or Expense	Net Operating Income
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
C-1	Yuma Manors Depreciation and Property Tax Expense	\$ (83,315)	\$ 50,381
C-2	Customer Advances for Construction	\$ (69,700)	\$ 42,148
C-3	Management Incentive Program	\$ (1,868,691)	\$ 1,130,012
C-4	Stock Based Compensation	\$ (820,915)	\$ 496,414
C-5	Supplemental Executive Retirement Expense	\$ (1,625,460)	\$ 982,929
C-6	American Gas Association Dues	\$ (80,138)	\$ 48,460
C-7	TRIMP Surcharge	\$ (920,914)	\$ 556,884
C-8	A&G Expenses - Annualized Paiute Allocation	\$ (23,447)	\$ 14,179
C-9	Interest on Customer Deposits	\$ 148,852	\$ (90,012)
C-10	Interest Synchronization	\$ -	\$ (237,509)
C-11	Flow Back Excess Deferred Income Taxes	\$ -	\$ 147,345
C-12	Injuries and Damages	\$ (861,717)	\$ 521,087
C-13	Leased Aircraft Operating Costs	\$ (32,814)	\$ 19,843
C-14	El Paso Natural Gas Rate Case Expense	\$ (477,415)	\$ 288,697
C-15	New Intangible Plant Annualized Amortizations	\$ (181,069)	\$ 109,494
	Total of Staff's Adjustments to Net Operating Income	\$ (6,896,743)	\$ 4,080,352
	Adjusted Net Operating Income per Southwest Gas		\$ 73,180,098
	Adjusted Net Operating Income per Staff		\$ 77,260,450

Concerning Southwest's Arizona costs related to the natural gas Transmission Integrity Management Program ("TRIMP"), I recommend that:

1) The current TRIMP deferral and surcharge mechanism that was ordered by the Commission in Decision No. 68487 for a 36-month period will continue for the remainder of the 36-month period. This surcharge, which Southwest has indicated it will be updating in the near future, would continue the 50/50 sharing ordered by the Commission in Decision No. 68487. Any over- or under-recovery of the 50 percent of TRIMP costs as of February 28, 2009 (the end of the 36-month period), would be addressed in the TRIMP surcharge for the subsequent period.

2) After the TRIMP surcharge ordered by the Commission in Decision No. 68487 is completed (which is currently expected to occur by February 28, 2009), a new TRIMP surcharge would replace it. The new TRIMP surcharge would be designed to recover \$921,000 of TRIMP costs over the initial twelve-month period (currently expected to be March 2009 through February 2010). Providing for an annual recovery of \$921,000 of TRIMP costs, divided by a test year rate case volume of 743,110,918 therms would produce a DOT TRIMP surcharge of \$0.00124 per therm. TRIMP surcharge revenue and TRIMP costs would be recorded by Southwest into Account 182.3. Starting with the March 2009 TRIMP surcharge period, the 50 percent shareholder responsibility for TRIMP costs would cease.

3) The TRIMP revenue and costs in Southwest's base rate filing should be removed, since prospective recovery would continue to be governed by the existing and the replacement TRIMP surcharge mechanisms, described above.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a

1 member of the American Bar Association ("ABA"), and the ABA sections on Public
2 Utility Law and Taxation.

3
4 **Q. Please summarize your professional experience.**

5 A. Subsequent to graduation from the University of Michigan, and after a short period of
6 installing a computerized accounting system for a Southfield, Michigan realty
7 management firm, I accepted a position as an auditor with the predecessor CPA firm to
8 Larkin & Associates in July 1979. Before becoming involved in utility regulation where
9 the majority of my time for the past 29 years has been spent, I performed audit,
10 accounting, and tax work for a wide variety of businesses that were clients of the firm.

11
12 During my service in the regulatory section of our firm, I have been involved in rate cases
13 and other regulatory matters concerning electric, gas, telephone, water, and sewer utility
14 companies. My present work consists primarily of analyzing rate case and regulatory
15 filings of public utility companies before various regulatory commissions, and, where
16 appropriate, preparing testimony and schedules relating to the issues for presentation
17 before these regulatory agencies.

18
19 I have performed work in the field of utility regulation on behalf of industry, state attorney
20 generals, consumer groups, municipalities, and public service commission staffs
21 concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona,
22 Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois,
23 Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey,
24 New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina,
25 South Dakota, Texas, Utah, Vermont, Washington, Washington D.C., and Canada as well
26 as the Federal Energy Regulatory Commission and various state and federal courts of law.

1 **Q. Have you prepared an attachment summarizing your educational background and**
2 **regulatory experience?**

3 A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.
4

5 **Q. On whose behalf are you appearing?**

6 A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or
7 "Commission") Utilities Division Staff ("Staff").
8

9 **Q. Have you previously testified before the Arizona Corporation Commission?**

10 A. Yes. I have testified before the Commission previously on a number of occasions.
11 Recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving
12 an emergency rate increase request by Arizona Public Service Company ("APS" or
13 "Company"), and concerning APS's proposed depreciation rates in Docket Nos. E-
14 01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, a proceeding involving
15 APS base rates and other matters. I also testified before the Commission in the most
16 recent UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-01013
17 and G-04204A-05-0831, and in the most recent UNS Electric, Inc. rate case Docket No.
18 E-04204A-06-0783.
19

20 **Q. What is the purpose of the testimony you are presenting?**

21 A. The purpose of my testimony is to address the rate base, adjusted net operating income
22 and revenue requirement proposed by Southwest Gas Corporation ("SWG," "Southwest"
23 or "Company").
24

1 **Q. Have you prepared any exhibits to be filed with your testimony?**

2 A. Yes. Attachments RCS-2 through RCS-6 contain the results of my analysis and copies of
3 selected documents that are referenced in my testimony, respectively.
4

5 **II. REVENUE REQUIREMENT**

6 **Q. What issues are addressed in your testimony?**

7 A. My testimony addresses the Company's proposed revenue requirement and selected other
8 issues.
9

10 **Q. What revenue increase has been requested by SWG?**

11 A. SWG is requesting an increase in base rate revenues of \$50.22 million or approximately
12 12.6 percent, based on adjusted revenues at current rates of \$399.2 million. The revenue
13 amount is from Company Schedule C-1 in Southwest's filing and is also shown on Staff
14 Schedule C on Attachment RCS-2.
15

16 **Q. What revenue increase does Staff recommend?**

17 A. Staff recommends a revenue increase of \$29.57 million on adjusted fair value rate base.
18 As shown on Schedule A, on original cost rate base ("OCRB") my calculations show a
19 jurisdictional revenue deficiency of \$29.57 million. On adjusted fair value rate base
20 ("FVRB") under Staff's option 1, which uses a fair value rate of return of 6.80 percent, I
21 show a base rate increase of \$29.00 million. Similar to Staff's recommendations in a
22 recent remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City
23 Water Company, Staff is also presenting the Commission with an option 2 for the fair
24 value rate of return for SWG. While Staff is not recommending that the Commission
25 adopt option 2 in this case, under option 2 the fair value rate of return for SWG is 7.09
26 percent, and the jurisdictional revenue deficiency is approximately \$35.94 million.

1 Attachment RCS-2, Schedule D, shows the development of Staff's recommended fair
2 value rate of return to be applied to FVRB. The testimony of Staff witness David Parcell
3 also addresses the determination of the fair value rate of return.
4

5 **A. Test Year**

6 **Q. What test year is being used in this case?**

7 A. SWG's filing is based on the historic test year ended April 30, 2007. Staff's calculations
8 use the same historic test year.
9

10 **Q. Could you please discuss the test year concept?**

11 A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to
12 the historic test year amounts to ensure that there is a matching of investment, revenues
13 and expenses. Rate base items, such as plant in service and accumulated depreciation, are
14 based on the actual level as of the end of the historic test year. Several rate base items that
15 tend to fluctuate from month to month, such as materials and supplies and prepayments,
16 are based on a test year average level. Since end of test year net plant in service is used,
17 revenues are annualized based on end of test year customer levels. Additionally, certain
18 expenses, such as depreciation and payroll costs, are annualized based on end of test year
19 levels. This is to ensure that the going-forward revenue and expense levels are matched
20 with the investment (net plant-in-service) used to serve those customers.
21

22 As time goes forward, changes in the Company's cost structure will occur. For example,
23 rate base will increase as new plant is added to serve new customers, revenue will increase
24 as customers are added, expenses will fluctuate, etc. It is very important to be consistent
25 with a test period approach to ensure that there is a consistent matching between

investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Summary of Company Proposed and Staff Adjusted Revenue Requirement

Q. What did your review of SWG's filing indicate?

A. As shown on Attachment RCS-2, Schedule A, I have calculated a base rate revenue deficiency on OCRB of \$29.57 million. As also shown on Attachment RCS-2, Schedule A, based on the fair value rate of return recommended by Staff witness David Parcell and the adjustments to SWG's rate base and net operating income recommended by myself and other Staff witnesses, I have calculated a jurisdictional base rate revenue requirement deficiency on FVRB of \$29.00 million. SWG should be authorized a base rate increase of \$29.57 million in this case because, this is between the \$29.00 million on adjusted fair value rate base under Staff's option 1, which uses a fair value rate of return of 6.80 percent, and the revenue requirement under fair value option 2. Similar to Staff's recommendations in a recent remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City Water Company, Staff is also presenting the Commission with an option 2 for the fair value rate of return for SWG. Under option 2, which Staff is not recommending the Commission adopt, the fair value rate of return for SWG is 7.09 percent, and the jurisdictional revenue deficiency is approximately \$35.71 million.

C. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base

1 adjustment Schedules B-1 through B-7 and net operating income adjustment Schedules C-
2 1 through C-15.

3
4 **Q. What is shown on Schedule A of Attachment RCS-2?**

5 A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement
6 determination. Schedule A presents the overall financial summary, giving effect to all the
7 adjustments I am recommending in my testimony. This schedule presents the change in
8 the Company's gross revenue requirement needed for the Company to have the
9 opportunity to earn Staff's recommended rate of return on Staff's proposed Original Cost
10 and FVRB. The rate base and operating income amounts are taken from Schedules B and
11 C, respectively. The overall rate of return on original cost rate base of 8.88 percent, as
12 presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for
13 convenience, as are the derivation of Staff's two options for the fair value rate of return.
14 Columns D and E of Schedule A present Staff's determination of the base rate revenue
15 deficiency on FVRB using Staff's two proposed alternatives for the fair value rate of
16 return. Schedule D presents the original cost and fair value rate of return recommended in
17 the prefiled testimony of Mr. Parcell.

18
19 The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting
20 the operating income available on line 4 (operating income as adjusted) from the required
21 operating income on line 3. Line 7 represents the gross revenue requirement, which is
22 obtained by multiplying the income deficiency by the gross revenue conversion factor
23 ("GRCF"). The derivation of the GRCF is shown on Schedule A-1.
24

1 **Q. How does the GRCF recommended by Staff compare with the GRCF contained in**
2 **SWG's filing?**

3 A. As shown on Schedule A-1, Staff recommends a GRCF of 1.6586. This is the same as the
4 GRCF of 1.6586 used in SWG's filing.

5
6 **Q. What is shown on Schedule B?**

7 A. Schedule B presents SWG's proposed adjusted test year Original Cost and Fair Value rate
8 base and Staff's proposed adjusted test year Original Cost and Fair Value rate base. The
9 beginning rate base amounts presented on Schedule B are taken from the Company's
10 filing for the test year, specifically SWG Schedule B-1. Staff's recommended adjustments
11 to rate base are summarized on Schedule B.1. I have prepared a Schedule B.1 for
12 adjustments to Southwest's proposed original cost rate base, and a Schedule B.1 for
13 Reconstruction Cost New Depreciated ("RCND") rate base adjustments.

14
15 Schedules B-1 through B-6 provide further support and calculations for the rate base
16 adjustments Staff is recommending.

17
18 **Q. What is shown on Schedule C?**

19 A. The starting point on Schedule C is SWG's adjusted test year net operating income, as
20 provided on Company Schedule C-1. Staff's recommended adjustments to SWG's
21 adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the
22 adjustments are discussed in this testimony.

23
24 Schedules C-1 through C-14 provide further support and calculations for the net operating
25 income adjustments Staff is recommending.

26

1 **Q. What is shown on Schedule D?**

2 A. Schedule D summarizes the capital structure and cost of capital that was proposed by
3 SWG and the capital structure and cost of capital that is recommended by Staff witness
4 Parcell. Schedule D also presents the derivation of Staff's recommended fair value rate of
5 return for use with the Staff's adjusted fair value rate base.

6
7 **D. Return on Fair Value Rate Base**

8 **Q. How was the fair value basis of rate base determined?**

9 A. As shown on Attachment RCS-2, Schedule B, the fair value rate base was determined by
10 averaging Original Cost and RCND rate base information. For purposes of this
11 presentation, I have used the Company's RCND information as the starting point for
12 Staff's derivation of the fair value rate base. As described in my testimony concerning
13 RCND rate base, I have made an adjustment to the Accumulated Deferred Income Tax
14 component of RCND rate base. This is addressed in Staff Adjustment B-7.

15
16 **Q. How did SWG determine the rate of return to apply to fair value rate base in its**
17 **filing?**

18 A. In SWG's own filing, as shown on Schedule A-1, the Company adjusted the return that is
19 to be applied to fair value rate base downward, consistent with long-standing Commission
20 practice, such that the revenue requirement produced by both the original cost rate base
21 and the fair value rate base were exactly the same and would not result in an excessive
22 return on equity to the utility. On its Schedule A-1, SWG shows the exact same Adjusted
23 Operating Income and Required Operating Income amounts on the Company's proposed
24 Original Cost and on its proposed Fair Value rate base. On that Schedule in the Fair
25 Value column, Southwest calculates an increase in gross revenue requirements of \$50.22
26 million.

1 **Q. Has the Commission's traditional calculation of return on fair value rate base been**
2 **called into question by a recent Court of Appeals decision?**

3 A. Yes. The Commission's traditional calculation of return on fair value rate base calculation
4 has been called into question by a recent Arizona Court of Appeals ruling involving
5 Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that
6 Staff's determination of operating income ignored fair value rate base, and that the
7 Commission must use fair value rate base to set rates per the Arizona Constitution.

8
9 **Q. What guidance for calculating the return on fair value rate base does that Court of**
10 **Appeals decision provide?**

11 A. First, the Court of Appeals specifically stated that the Commission was not bound to apply
12 an authorized rate of return that was developed for use with an original cost rate base,
13 without adjustment, to the fair value rate base. Page 9 of the Court of Appeals decision
14 stated that: "Chaparral City ... asks that the Commission be directed to apply the
15 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chaparral
16 City contends was done here." At page 13, paragraph 17, the Court of Appeals decision
17 states as follows: "The Commission asserts that it was not bound to use the weighted
18 average cost of capital as the rate of return to be applied to the FVRB. The Commission is
19 correct." Thus, the Court of Appeals clearly stated that the Commission is not bound to
20 apply to the FVRB the same weighted average cost of capital that was developed for
21 application to the OCRB.

22
23 At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the
24 Commission cannot ignore its constitutional obligation to base rates on a utility's fair
25 value. The Commission cannot determine rates based on the original cost, or OCRB, and
26 then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate

1 of return. Such a method is inconsistent with Arizona law.” At page 13, the decision
2 states: “If the Commission determines that the cost of capital analysis is not the
3 appropriate methodology to determine the rate of return to be applied to the FVRB, the
4 Commission has the discretion to determine the appropriate methodology.”

5
6 **Q. Has a remand proceeding been established by the Commission to address the**
7 **calculation of the return on fair value rate base, i.e., to address the ruling in the**
8 **Court of Appeals decision?**

9 A. Yes. The Commission has opened a docket to address such issues in a Chaparral City
10 remand proceeding.
11

12 **Q. How has Staff addressed the ruling in the Court of Appeals decision for purposes of**
13 **the current SWG rate case?**

14 A. In view of the Court of Appeals decision in the Chaparral City case, Staff has
15 appropriately adjusted the weighted cost of capital to derive a fair value rate of return to
16 apply to the utility’s fair value rate base. David Parcell’s direct testimony in the instant
17 rate case describes Staff’s derivation of the fair value return on fair value rate base
18 calculations in view of the recent Court of Appeals decision concerning Chaparral. Staff
19 has also recently addressed the determination of a fair value rate of return to be applied to
20 FVRB in the Chaparral City remand proceeding, Docket No. W-02113A-04-0616.

21
22 Schedule D of Attachment RCS-2 shows the derivation of the fair value rate of return for
23 application to the FVRB. On Schedule A of Attachment RCS-2, I have applied Staff’s
24 adjustment to the weighted cost of capital as described by Mr. Parcell in his Direct
25 Testimony. As noted above, Staff has presented the Commission with two options for the
26 fair value rate of return applicable to FVRB.

III. RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to SWG's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

Summary of Rate Base	Company	Staff	Difference
Original Cost Rate Base	\$ 1,094,790,047	\$ 1,070,195,857	\$ (24,594,190)
RCND Rate Base	\$ 1,843,481,069	\$ 1,716,500,027	\$ (126,981,042)
Fair Value Rate Base	\$ 1,469,135,559	\$ 1,393,347,942	\$ (75,787,617)

Adjustments to Original Cost Rate Base

Q. Please discuss Staff's adjustments to Southwest's proposed original cost rate base.

A. Staff has made five adjustments to Southwest's proposed original cost rate base. These have been designated as Staff Adjustments B-1 through B-6. Each adjustment is discussed below. I have also made an adjustment to Southwest's proposed RCND rate base, for trending the Accumulated Deferred Income Tax ("ADIT") component, which is also discussed below and shown in Staff Adjustment B-7.

B-1 Yuma Manors Pipe Replacement

Q. Please explain the adjustment for the Yuma Manors Pipe Replacement.

A. As shown on Schedule B-1, this adjustment reduces rate base by \$1,092,448. Staff's concerns regarding Southwest's deficient pipe maintenance are discussed in the testimony of Staff engineer Corky Hanson. This adjustment restates test year rate base as if the pipe replacement project undertaken by Southwest in the Manors subdivision in Yuma, Arizona, did not exist. Plant in Service accounts for Mains (Account 376) and Services

(Account 380) are restated to effectively eliminate the costs related to the Company's failure to adequately maintain the pipe which led to its replacement. Accumulated Depreciation as of April 30, 2007, the end of the test year, is also restated similarly. The components of the adjustment are summarized on Schedule B-1. Plant in Service is reduced by \$1.232 million. Accumulated Depreciation is increased by \$139,314. Net rate base is decreased by \$1.092 million. The source for the amounts used in the adjustment is Southwest's response to Staff data requests STF-7-1 and LA-11-6.¹

Q. Is there an adjustment to operating expenses related to this adjustment?

A. Yes. Staff Adjustment C-1 is related to this adjustment and reduces test year Depreciation Expense and Property Tax Expense, based on the adjustment to Plant in Service and Net Plant, respectively.

B-2 Customer Advances for Construction

Q. Please explain Staff's Adjustment B-2.

A. This adjustment decreases rate base by \$11.285 million to reflect the end-of-test-year balance for Customer Advances. Rate base is also increased by \$3.885 million for the related impact on Accumulated Deferred Income Taxes ("ADIT").

Q. Why should the end-of-test-year balance be used for Customer Advances?

A. The end-of-test-year balance for Customer Advances should be used for at least two reasons.

First, Customer Advances are related to Plant, and the end-of-test-year balances for Plant in Service and Accumulated Depreciation are used in rate base. Revenues have been

^{1 1} See Attachment RCS-5 for copies of data request responses referenced in this testimony.

1 annualized to year-end conditions, and expenses, such as Depreciation and Property Taxes
2 have also been adjusted to year-end conditions, to properly "match" with the use of year-
3 end plant in rate base.

4
5 Second, and perhaps more importantly, the end-of-test-year balance for Customer
6 Advances is more representative of current and ongoing conditions than would be an
7 average test year balance. As shown on Schedule B-2, the monthly balance of Customer
8 Advances has increased in each month of the test year. Thus, unlike some other rate base
9 components, where the balances fluctuate up and down from month to month, the steady
10 upward trend in Customer Advances indicates that this is a growing balance.
11 Consequently, the average balance is not representative of conditions at the end of the test
12 year, or on a going-forward basis. A graph of the monthly Customer Deposit balances,
13 which illustrates this trend, is also presented on Schedule B-2.

14
15 **B-3 Working Capital**

16 **Q. Have you reviewed the Company's request for a working capital allowance?**

17 **A.** Yes. The Company's proposed working capital request of approximately \$5.68 million
18 consists of three separate subcomponents. The subcomponents are:

- 19
20 (1) a negative cash working capital balance of \$10.38 million based on a lead/lag study;
21 (2) a thirteen-month average materials and supplies balance of \$12.39 million; and
22 (3) a thirteen-month average prepayments balance of \$3.68 million.
23

B-4.1 Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does SWG have a positive or negative cash working capital requirement?

A. SWG has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did SWG present a lead/lag study in support of its cash working capital requirement?

A. Yes, SWG performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Has SWG made any revisions to the cash working capital calculation included in its filing?

A. No, none of which I am aware.

1 **Q. Are you recommending any revisions to SWG's cash working capital request?**

2 A. Yes. At this time, as shown on Schedule B-3, I have reflected the impact of Staff's
3 adjustments to operating expenses and impacts on revenue based taxes. I also propose to
4 synchronize the calculation of cash working capital with Staff's recommended revenue
5 increase.²

6
7 **Q. What is the result of your cash working capital calculation?**

8 A. As shown on Schedule B-3, at this time I have increased SWG's filed cash working
9 capital by approximately \$54,000.

10
11 **Q. What revenue lag does Southwest propose and what are its components?**

12 A. Southwest proposes a total revenue lag of 39.53 days, based on the following three
13 components:

14

Description	Lag Days
Cycle	15.20
Read to Bill	2.90
Bill to Collection	21.43
Total revenue lag days	<u>39.53</u>

15
16 **Q. Do you have any concerns about apparent omissions in Southwest's lead-lag study?**

17 A. Yes. It appears that Southwest has omitted reflecting the additional cash payment lag
18 associated with revenue-based taxes and assessments. I have recently reviewed lead-lag
19 studies for other Arizona utilities, including UNS Gas, UNS Electric and Tucson Electric
20 Power Company. Those lead-lag studies have included a component for the additional
21 cash payment lag related to the payment of revenue-based taxes and assessments. During
22 the period between (1) when the utility collects the revenue based taxes from ratepayers

² Such synchronization has not yet been reflected at this time, but would be incorporated in Staff's surrebuttal filing.

1 and (2) when the utility remits those funds to the taxing or assessing authority, the
2 Company has use of the ratepayer-provided funds. Because the revenue based taxes are
3 directly related to the provision of utility service and because there is a cash payment and
4 the utility typically has the use of ratepayer-provided funds for some period, it is
5 appropriate to reflect the payment lag associated with such taxes in the determination of
6 cash working capital using a lead-lag study.

7
8 **Q. How did Southwest consider revenue-based taxes in its lead-lag study?**

9 A. Southwest considered revenue-based taxes in its lead-lag study by adding such taxes to
10 billed revenues in order to calculate the 21.43 day billing to collection lag. However,
11 based on my review to date, it does not appear that Southwest reflected the additional
12 payment lag associated with such taxes as a source of ratepayer-provided funds. Follow
13 up discovery has been issued to Southwest in Staff data requests STF-11-2 and STF-11-3
14 concerning this issue.³ The Company's response to STF-11-2 indicates that it did not
15 calculate the revenue-based taxes in its lead-lag study. The Company's response to STF-
16 11-3, parts 1 through 3, indicates that SWG has not performed any study related to
17 revenue-based taxes. The Company's response to STF-11-3 supplied "raw data" in a
18 format that will be time-consuming to evaluate. Consequently, at a later point in this
19 proceeding, such as with Staff's surrebuttal testimony, it may be necessary to incorporate
20 an adjustment to cash working capital for the impact of the payment lag associated with
21 revenue-based taxes and assessments.

22

^{3 3} See Attachment RCS-5.

B-4 Customer Deposits

Q. Please explain Staff's Adjustment B-4.

A. This adjustment decreases rate base by \$2.48 million to reflect the end-of-test-year balance for Customer Deposits.

Q. Why should the end-of-test-year balance be used for Customer Deposits?

A. The end-of-test-year balance be used for Customer Deposits should be used for at least two reasons.

First, Customer Deposits are related to the number of customers that the utility is serving. End-of-test-year balances for Plant in Service and Accumulated Depreciation are used in the determination of Southwest's rate base. Revenues have been annualized to year-end conditions, and expenses, such as Depreciation and Property Taxes have also been adjusted to year-end conditions, to properly "match" with the use of year-end plant in rate base. Using the end-of-test-year balance of Customer Deposits thus better matches that balance with the use of year-end customer levels that were used to annualize utility revenues to test year-end conditions.

Second, and perhaps more importantly, the end-of-test-year balance for Customer Deposits is more representative of current and ongoing conditions than would be an average test year balance. As shown on Schedule B-4, the monthly balance of Customer Deposits has increased in each month of the test year. Thus, unlike some other rate base components, where the balances fluctuate up and down from month to month, the steady upward trend in Customer Deposits indicates that this is a growing upward trend, and the average balance is not representative of conditions at the end of the test year, or on a going-forward basis. Perhaps even more compelling regarding the trend of steady growth Southwest has experienced in the monthly balances of Customer Deposits is shown on

1 Schedule B-4, page 2. In the 61 months from September 2002 through September 2007,
2 the Company's balance of Customer Deposits has increased in every single month. A
3 graph of the monthly Customer Deposit balances from September 2002 through
4 September 2007, which illustrates this trend of steady growth to (and even beyond) the
5 end of the test year, is presented on Schedule B-4, page 3.

6
7 **B-5 Miscellaneous Accumulated Deferred Income Tax, Account 190**

8 **Q. Please explain the adjustment to Miscellaneous Accumulated Deferred Income Taxes**
9 **("ADIT") that were included in rate base by Southwest for Account 190.**

10 **A. This adjustment is shown on Schedule B-5. It decreases rate base by \$13.132 million to**
11 reflect that a substantial amount of the Company's proposed rate base addition for
12 Account 190 has been removed and, consequently, does not exist on a going-forward
13 basis.

14
15 As shown on Schedule B-5, SWG's proposed rate base amount for Account 190 is based
16 on a \$36.82 million amount, before allocation to Arizona. Per the Company's response to
17 STF-11-10(a)⁴, this \$36.82 million represents the total Alternative Minimum Tax Credit
18 (AMTC) for Southwest Gas Corporation as of 12/31/06. That response also indicates that
19 there is a short-term (i.e., "current") and a long-term portion of the \$36.82 million. Sub-
20 account 19002110 for \$25 million is the current portion of the AMTC that is expected to
21 be utilized during the next 12 months, i.e., during the 2007 tax year. Sub-account
22 19002115 is the non-current portion of the AMTC and represents the amount that is
23 expected to be utilized sometime after the 2007 tax year.

24

⁴ See Attachment RCS-5

1 Federal income tax information reviewed at Southwest's offices confirms that a
2 substantial portion of the AMT carry-forward has been used by the Company in 2007.
3 SWG made an updated estimate of the amount of 2007 federal corporation income tax that
4 it would owe on its 2007 tax return. The most current estimate made by the Company was
5 as of March 15, 2008, when SWG prepared its federal corporate tax return extension
6 filing. The amount of AMT carry-forward that was used by the Company, therefore, is no
7 longer being carried as an ADIT balance in Account 190. On a going-forward basis, the
8 amount of AMTC that was applied in 2007 to reduce SWG's income taxes no longer
9 exists, and should therefore be removed from rate base..
10

11 **Q. Are you satisfied that the remaining balance in Account 190 is representative of a**
12 **reasonable and continuing level of tax prepayment related to the AMT on a going-**
13 **forward basis?**

14 A. For the most part, yes. Southwest currently expects to be able to apply an additional
15 amount of its AMT carry-forward to reduce income tax in tax year 2009 (but not in tax
16 year 2008); therefore, the remaining Account 190 balance is expected to remain during
17 2008 and beyond until it can be utilized. Consequently, the remainder appears to
18 represent a continuing tax prepayment on a going-forward basis.
19

20 **Q. What other concerns do you have regarding SWG's proposed rate base addition for**
21 **ADIT in Account 190 that relates to AMT?**

22 A. There is also a concern that some portion of the ADIT balance in Account 190 was caused
23 by AMT components that are not considered in the determination of utility revenue
24 requirements. An example of one such item would be the increase in cash surrender value
25 of company owned life insurance ("COLI"). Ideally, only the going-forward portion of
26 the ADIT balance in Account 190 that is for AMT items that relate to revenue and

1 expense timing differences that would be allowable in the determination of the base rate
2 revenue requirement for Southwest's Arizona gas utility operations should be included in
3 rate base. The incremental portion of Southwest's AMT carry-forward balance that
4 relates to non-allowable and/or non-utility items should not be included in rate base.

5
6 **Q. Is Staff recommending any additional adjustment to the rate base amount for**
7 **Account 190 for non-utility or non-allowable AMT carry-forward components at this**
8 **time?**

9 A. No. An estimate prepared by Southwest's Tax Department of the impact of such items
10 shows that the impact is relatively minor in comparison with the total AMT carry-forward
11 balance that comprises Southwest's ADIT balance in Account 190 as of December 31,
12 2007. The detail of the federal AMT calculation, and its interaction with the "regular"
13 federal corporate income tax, can be quite complex. If the non-utility portion of
14 Southwest's AMT carry-forward balance appeared to represent a significant addition to
15 rate base, the additional analysis needed to accurately quantify and eliminate the non-
16 utility components would be justified. However, based on the facts known to date in the
17 current case, the far more important concern regarding Account 190 is that the Company's
18 proposed rate base balance be adjusted to a more representative going-forward level by
19 removing the portion of the AMT carry-forward that Southwest has utilized in tax year
20 2007, as described above, and which therefore does not represent a continuing part of the
21 prepaid balance.

22
23 **Q. Did this adjustment also have an impact on RCND rate base?**

24 A. Yes. As shown on Schedule B-5, line 3, RCND rate base is decreased by \$20,109,648.
25 The Company's RCND factors for the ADIT in Account 190 used to derive this
26 adjustment to RCND rate base are the same ones used, by year, as the RCND factors used

1 in Staff Adjustment B-7, discussed below. Schedule B-5, page 2, shows the RCND
2 factors applicable to the balance in Account 190.

3
4 **B-6 New Intangible Plant Placed Into Service By December 31, 2007**

5 **Q. Please explain Staff's adjustment for new intangible plant placed into service by**
6 **December 31, 2007.**

7 A. Southwest's filing included an adjustment (Company Adjustment No. 14) to add to rate
8 base \$1,696,000 for new intangible plant that the Company projected would be placed into
9 service by December 31, 2007. Staff Adjustment B-6 adjusts the Company's estimate for
10 actual new intangible plant that was placed into service by December 31, 2007. As shown
11 on Schedule B-6, Intangible Plant allocated to Arizona is reduced by \$543,210.

12
13 **Q. Is there a related adjustment for the annualized amortization?**

14 A. Yes. A related adjustment for the impact upon annualized amortization expense is
15 presented in Staff Adjustment C-15.

16
17 **Adjustments to Reconstruction Cost New Depreciated Rate Base**

18 **Q. Please describe Staff's adjustments to RCND rate base.**

19 A. For the most part, Staff's adjustments to Southwest's proposed RCND rate base are the
20 same amounts as Staff's adjustments to OCRB. Staff is making an adjustment to trend the
21 amount of Accumulated Deferred Income Tax in the RCND rate base.

22
23 **B-7 Trended RCND Amount for Accumulated Deferred Income Taxes**

24 **Q. Please explain Staff's adjustment for the ADIT amount in the RCND rate base.**

25 A. When reviewing Southwest's RCND rate base, it was discovered that Southwest used the
26 same Accumulated Deferred Income Tax amounts in OCRB and RCND rate base. This

1 did not have any impact on Southwest's proposed revenue requirement on fair value rate
2 base, because of the way in which Southwest calculated the required net operating income
3 on FVRB. However, it does have an impact on Staff's proposed revenue requirement on
4 FVRB. The portion of Southwest's ADIT balance that relates to Plant and Accumulated
5 Depreciation should be trended in order to derive the corresponding RCND value. In
6 response to inquiries for the information needed to derive the trended RCND value for
7 ADIT, Southwest provided an Excel file. That information was used to derive Staff's
8 recommended RCND amount for the ADIT balance. As shown on Schedule B-7, this
9 Staff adjustment increases the amount of ADIT that Southwest used in deriving its RCND
10 rate base for ADIT by \$95,409,229. Because the ADIT balance is a net offset to rate base,
11 this adjustment decreases Southwest's filed RCND rate base by the \$95.409 million.
12

13 **IV. ADJUSTMENTS TO OPERATING INCOME**

14 **Q. Please describe how you have summarized Staff's proposed adjustments to operating**
15 **income.**

16 A. Schedule C summarizes Staff's recommended net operating income. Schedule C.1
17 presents Staff's recommended adjustments to Arizona test year revenues and expenses.
18 The impact on state and federal income taxes associated with each of the recommended
19 adjustments to operating income are also reflected on Schedule C.1. SWG's proposed
20 adjusted test year net operating income is \$73.181 million, whereas Staff's recommended
21 adjusted net operating income is \$77.160 million. The recommended adjustments to
22 operating income are discussed below in the same order as they appear on Schedule C.1.
23

C-1 Yuma Manors Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-1.

A. This adjustment is related to Adjustment B-1. It removes \$54,370 of Depreciation Expense and \$28,945 of Property Tax Expense related to the adjustment to Plant in Service for the Yuma Manors pipe replacement project.

Q. How did Staff determine its recommended assessment rate for property taxes?

A. This adjustment reflects the known statutory assessment ratio of 23 percent applicable for 2009, when rates in this case are expected to be effective. The Arizona State Legislature passed House Bill No. 2779, which set a new rate schedule for property tax assessments. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 in 0.5 percent steps each year until a 20 percent rate is attained in 2015. The Company's calculation also used a 23 percent assessment rate.

C-2 Gain on Sale of Property in Cave Creek, AZ

Q. Please explain Staff Adjustment C-2.

A. This adjustment reflects ratepayer sharing of 50 percent of the gain realized by SWG on the sale of property in Cave Creek, Arizona. As described in SWG's response to Staff data request STF-1-96⁵:

In November 2003, the Commission authorized Southwest to acquire the gas distribution property of Black Mountain Gas (BMG). In September 2007, the Company sold land and structures in Cave Creek, Arizona, which had been included in gas plant in service. The property acquired in the BMG acquisition had a net book value of \$1,025,676 at the time of the sale. The land had a net book value of \$502,044 and the structure had a net book value of \$523,632. The net proceeds of the 2007 sale were \$1,433,107, resulting in a gain of \$418,196. This gain was recorded in Account 2530, "Other Deferred Credits". Attached is a schedule showing

⁵ See Attachment RCS-5.

1 *the calculation of the gain. Historically, the Commission has amortized,*
2 *over a multiple-year period, the gain or loss on Southwest's disposition of*
3 *property previously included in rate base, 50 percent above-the-line to*
4 *ratepayers and 50 percent below-the-line to shareholders.*

5
6 Staff Adjustment C-2 reflects this treatment. A normalization period of three years was
7 used. Three years is the same period that Southwest has used for normalizing its proposed
8 allowance for rate case costs. A shown on Schedule C-2, pre-tax operating income is
9 increased by \$69,700. SWG's response to STF-9-1 confirmed the \$69,700 amount.⁶

10
11 **C-3 Management Incentive Program Expense**

12 **Q. Please explain Staff Adjustment C-3.**

13 A. This adjustment provides for the allocation of 50 percent of the test year expense for the
14 Management Incentive Program ("MIP") to shareholders. Test year expense for the MIP
15 proposed by Southwest is reduced by \$2.019 million. Related payroll tax expense is
16 increased by \$150,577.

17
18 **Q. Please explain why payroll tax expense is being increased in Staff Adjustment C-3.**

19 A. SWG's response to STF-11-15 states that Southwest's annualized labor (shown on the
20 Company's workpaper for Schedule C-2, Adjustment No. 3) does not include MIP
21 compensation or stock based compensation.⁷ Consequently, the cost of service filed by
22 SWG did not include annualized payroll taxes related to these two items of compensation.
23 This adjustment, therefore, provides for annualized payroll tax expense on the portion of
24 MIP that is being allowed in rates.

25

⁶ See Attachment RCS-5.

⁷ See Attachment RCS-5.

Q. Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program, such as Southwest's MIP.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the MIP expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

Q. Please briefly discuss the key provisions of the MIP.

A. SWG's MIP provides variable compensation to executives for the achievement of specific goals and benchmarks important to both the short-term and long-term success of the Company. A summary of the MIP award triggers is presented in the following table:

PERFORMANCE MEASURES AND WEIGHTS					
MEASURE	THRESHOLD	TARGET	MAXIMUM	WEIGHTING	SOURCE FOR MEASUREMENT
Absolute:					
Three-Year Weighted ROE	5.6%	8.0%	10.0%	20%	Gas segment ROE adjusted for CPI and customer growth
Customer to Employee Ratio	70%	100%	140%	20%	Target = prior year C/E target + 3% improved productivity
Customer Service Satisfaction	75%	85%	95%	20%	Quarterly surveys
Relative:					
ROE vs. Peer Group	25th Percentile	50th Percentile	75th Percentile	20%	Financial publications for distribution companies
Customer to Employee vs. Peer Group	51st Percentile	76th Percentile	90th Percentile	20%	Annual surveys
POTENTIAL	70%	100%	140%	100%	TOTAL

Note: No annual incentive awards will be payable unless the Company's dividends equal or exceed the prior year's dividends.

1 The MIP award is at risk each year based on performance relative to five measures. These
2 annual performance measures, which are equally weighted, include three absolute
3 measures, which include (1) three-year weighted return on equity, (2) customer to
4 employee ratio, (3) customer satisfaction survey result as well as two relative measures,
5 which include (4) current return on equity versus peers and (5) customer-to-employee
6 ratio versus peers. Each of these measurements has a threshold, target and a maximum.
7 At target, each measurement contributes 20 percent towards the total award for the year.
8 An award under a specific criteria may be given within a range from 70 percent at
9 threshold to 140 percent at maximum. There is no award under specific criteria for
10 performance under the threshold, and there is no incremental value for performance over
11 the maximum for any of the five criteria.

12
13 **Q. How are the MIP awards related to shareholder dividends?**

14 A. As noted above, two of the five MIP award criteria relate to return on equity.
15 Additionally, no annual incentive awards will be payable unless the Company's dividends
16 equal or exceed the prior year's dividends. This is an important factor because, if
17 shareholder dividends are decreased from the prior year, there is no incentive awards
18 under the MIP for that year.

19
20 **Q. What Southwest management personnel are eligible for the MIP award, and how is it**
21 **distributed?**

22 A. According to SWG's response to STF-1-49⁸, the MIP award opportunity is measured as a
23 percentage of base salary and varies by title as follows:
24

⁸ See Attachment RCS-5.

1	CEO	115%
2	President	100%
3	Executive VP	90%
4	Senior VP	75%
5	Vice President	50%
6	Director/Senior Manager (non-officers)	30%

7
8 Forty percent of the total award earned under the MIP is paid in cash immediately
9 following the financial close of the most current calendar year. The remaining 60 percent
10 is awarded through the issuance of performance shares, which are issued to the executives
11 and key management employees three years into the future.

12
13 **Q. Does Southwest recognize that its proposed treatment of MIP expense in the current**
14 **case represents a conscious deviation from principles and policies established in**
15 **prior Commission Orders?**

16 **A. Yes. Data request STF 1-87 asked⁹:**

17
18 *Are there any aspects of the Company's accounting adjustments and*
19 *revenue requirement claim which represents a conscious deviation from*
20 *the principles and policies established in prior Commission Orders? If so,*
21 *identify each area of deviation, and for each deviation explain the*
22 *Company's perception of the principle established in the prior*
23 *Commission orders, how the Company's proposed treatment in this rate*
24 *case deviates from the principles established in the prior Commission*
25 *orders, and the dollar impact resulting from such deviation. Show which*
26 *accounts are affected and the dollar impact on each account for each such*
27 *deviation.*

28
29 Southwest's response to this data request states in part that "Southwest is requesting full
30 cost recovery of its Management Incentive Program and Supplemental Executive
31 Retirement Plan."¹⁰

⁹ See Attachment RCS-5.

¹⁰ I discuss Staff's recommended adjustment for the SERP, below, in conjunction with Staff Adjustment C-5.

1 **Q. What reasoning does SWG give for its request to recover 100 percent of its MIP costs**
2 **despite prior Commission Orders?**

3 A. In her Direct Testimony at page 2, Company witness Hobbs stated that the Company's
4 management compensation and benefits package is designed to attract, retain and motivate
5 skilled management for the organization and that the compensation package is intended to
6 be reasonable, competitive, internally equitable and tied to performance.

7
8 Additionally, as described in Ms. Hobb's testimony at pages 2-3, utilizing recent publicly
9 available proxy statements of other western energy utilities (Proxy Peer Group), SWG
10 compared the total compensation (base salary, bonus, other, restricted stock awards,
11 options awards, non-equity incentive plan, long term incentive payout and all other
12 compensation) of its five highest paid employees to the five highest paid employees of
13 each Proxy Peer Group company and concluded that its management and executive
14 employees are compensated within a reasonable range. Based in part on the analysis
15 shown in her Exhibit __ LLH-1, Ms. Hobb's concludes that Southwest's executive
16 compensation package is prudent and reasonable.

17
18 **Q. If Ms. Hobb's Exhibit __ LLH-1 is going to be given weight as a justification for the**
19 **Company's proposal for charging ratepayers for Southwest's MIP expense, what**
20 **implications does that information have for other Arizona utilities?**

21 A. The type of self-serving analysis shown in Ms. Hobb's Exhibit __ LLH-1 should not be
22 determinative of the ratemaking treatment for incentive compensation in this or other
23 utility rate cases. However, if such analysis were to be relied upon for lowering the 50
24 percent allocation of MIP expense to Southwest's shareholders, the same information
25 would appear to support a much higher allocation to shareholders of the executive

1 compensation of other Arizona utilities, based on the worse ratios shown there for the
2 parent companies of other Arizona utilities which with Southwest has compared itself.

3
4 At page 5 of her direct testimony, Ms. Hobb's refers to her Exhibit ____ LLH-1, and states
5 that: "the difference is most evident in the compensation per customer amount. ...
6 Southwest demonstrates that the total compensation per customer for the five highest paid
7 Southwest executives is \$2.47. Only one company in the Proxy Peer Group has lower
8 compensation per customer for the five highest paid executives." Ms. Hobb's exhibit
9 shows that the worst ratio of executive compensation to customer is for Pinnacle West, the
10 parent of Arizona Public Service. At \$12.77 per customer, this exceeds the \$2.47 on Ms.
11 Hobb's exhibit for Southwest by 417 percent. Also, the executive compensation per
12 customer in Ms. Hobb's exhibit shown for UniSource Energy (parent of Tucson Electric
13 Power, UniSource Electric and UniSource Gas) is almost triple that shown for Southwest
14 (i.e., it exceeds the Southwest amount by 198 percent).

15
16 These comparative percentages are summarized in the following table:

17
18 Top Five Executives' Compensation Per Customer
19 Companies in Ms. Hobb's Exhibit with Arizona Utility Operations

Utility (Stock Symbol)	Executive Comp. per Customer	Percentage Excess Over SWG
Pinnacle West (PNW)	\$ 12.77	417%
UniSource (UNS)	\$ 7.37	198%
Southwest Gas (SWX)	\$ 2.47	N/A

20
21
22
23 Source: Southwest Gas witness Hobb's Exhibit ____ LLH-1
24

1 **Q. Does the methodology for comparing the per-customer executive compensation used**
2 **by Ms. Hobbs address the criteria that the Commission has found important in**
3 **deciding issues concerning utility incentive compensation in recent cases?**

4 A. No. Her methodology ignores the criteria the Commission has found important in
5 deciding this issue in recent cases.

6
7 In Decision No. 68487 (February 23, 2006), the Commission adopted Staff's
8 recommendation for an equal sharing of costs associated with the Company's MIP
9 expense. For example, in reaching its conclusion regarding SWG's MIP, the Commission
10 stated in part on page 18 of Order 68487 that:

11
12 *We believe that Staff's recommendation for an equal sharing of the costs*
13 *associated with MIP compensation provides an appropriate balance*
14 *between the benefits attained by both shareholders and ratepayers.*
15 *Although achievement of the performance goals in the MIP, and the*
16 *benefits attendant thereto, cannot be precisely quantified there is little*
17 *doubt that both shareholders and ratepayers derive some benefit from*
18 *incentive goals. Therefore, the costs of the program should be borne by*
19 *both groups and we find Staff's equal sharing recommendations to be a*
20 *reasonable solution.*

21
22 Ms. Hobbs has not refuted the fact that both shareholders and ratepayers derive some
23 benefit from incentive goals.

24
25 **Q. Do SWG's shareholders and customers both benefit from its MIP goals?**

26 A. Yes. In referencing the performance shares issued three years into the future as discussed
27 above, Ms. Hobbs states in her Direct Testimony at page 5, lines 4-8 that:

28
29 *"The longer-term performance shares act as a retention tool while*
30 *aligning the interests of management/executive employees, shareholders*
31 *and customers for continued financial and customer-oriented*
32 *performance."*

1 Shareholders benefit from the achievement of financial goals. Additionally, shareholders
2 benefit from the achievement of expense reduction and expense containment goals
3 between rate cases. Shareholders and ratepayers can both benefit from the achievement of
4 customer service goals.

5
6 **Q. Have the facts changed materially since the last Southwest Gas rate case such that a**
7 **different result concerning the sharing of MIP expense should occur?**

8 A. No, I don't believe so. The Company's MIP expense is significantly higher in the current
9 rate case than it was in the prior SWG rate case. However, the rationale for the 50 percent
10 allocation to shareholders of the MIP expense in the current case appears to be consistent
11 with the Commission's findings concerning MIP in Decision No. 68487.

12
13 **Q. Did Southwest Gas appeal Decision No. 68487?**

14 A. No.

15
16 **Q. Should the 50/50 ratepayer/shareholder sharing that the Commission has applied to**
17 **utility incentive compensation in SWG's last rate case be modified to a 100 percent**
18 **ratepayer responsibility for such cost based on the analysis presented by Ms. Hobbs?**

19 A. No. The 50/50 sharing of Southwest's MIP program cost ordered by the Commission in
20 Decision No. 68487 should continue to apply in the current Southwest Gas rate case.

21
22 **Q. Was an equal sharing of utility incentive compensation expense also ordered in the**
23 **Commission's recent decision in a rate case involving another Arizona gas**
24 **distribution utility?**

25 A. Yes, it was. In Decision No. 70011 (November 27, 2007), in the recent UNS Gas rate
26 case, Docket No. G-04204-06-0463 et al, the Commission stated in part on page 27 that:

We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

Q. How does the amount of SWG's MIP expense in the current case compare with the amount from SWG's prior rate case?

A. The following table¹¹ summarizes SWG's MIP expense in the current case, and Staff's recommended adjustment for MIP expense from Staff's surrebuttal testimony in SWG's last rate case, Docket No. G-0551A-04-0876:

Management Incentive Program Expense
Staff Proposed Treatment in Current SWG Rate Case
Compared with Staff Recommendation in Last SWG Rate Case

Line	Description	Current Case	SWG's Last Rate Case	Dollar Increase	Percent Increase
1	Test Year amount of Management Incentive Program Expense (Corporate)	\$7,416,322	\$ 3,366,667	\$ 4,049,655	120%
2	Allocation to Paiute (MMF)	\$ (293,686)			
3	Net of Allocation to Paiute	\$7,122,636	\$ 3,366,667		
4	Arizona Four Factor allocation rate per SWG Schedule C-1, sheet 17	56.70%	57.58%		
5	Test Year amount of Management Incentive Program Expense (Arizona)	\$4,038,535	\$ 1,938,518		
6	Ratepayerer allocation percentage	50%	50%		
7	50% Allocation of MIP Expense to Ratepayers	\$2,019,268	\$ 969,259	\$ 1,050,009	108%

Source:

Current case amounts - Attachment RCS-2, Schedule C-3

Prior case amounts - Docket No. G-0551A-04-0876, James Dorf surrebuttal, Schedule JJD-16 Revised

As shown in the above table, Southwest's MIP expense in the current rate case is 120 percent higher (i.e., more than double) than in the prior case. Also, Staff's proposed 50 percent allowance of MIP expense for Arizona operations in the current case is \$1.05 million or 108 percent higher (i.e., also more than double) than the \$969,259 amount from SWG's last rate case.

¹¹ Southwest's updated response to STF-1-78 corrected the MIP amount to \$5,919,502. Given the late date of this update, Staff will address the impact of this change in its surrebuttal testimony.

1 **Q. Is a significant portion of Southwest's MIP expense related to stock-based**
2 **compensation?**

3 A. Yes. SWG's response to data request STF-10-12 identifies \$3,587,416 as MIP stock-
4 based compensation expense.¹² Thus, almost half of SWG's total test year MIP expense is
5 related to stock-based compensation.

6
7 **Q. Did the Commission recently disallow another utility's stock based compensation in**
8 **a recent decision?**

9 A. Yes. In Decision No. 69663, from a recent APS rate case, the Commission adopted a
10 Staff recommendation in that case where cash-based incentive compensation expense was
11 allowed and stock-based compensation was disallowed. Additionally, page 36 of
12 Decision No. 69663 indicates that the Commission rejected an argument by APS that the
13 Commission not look at how compensation is determined or its individual components:

14
15 *"APS argues that the issue is whether APS compensation,*
16 *including incentives, is reasonable. APS does not believe that the*
17 *Commission should look at how that compensation is determined or its*
18 *individual components, but rather should just look at the total*
19 *compensation. The Company argues that the interests of investors and*
20 *consumers are not in fundamental conflict over the issue of financial*
21 *performance, because both want the Company to be able to attract needed*
22 *capital at a reasonable cost."*

23
24 *"We agree with Staff that APS' stock-based compensation expense*
25 *should not be included in the cost of service used to set rates. Contrary to*
26 *APS' argument that we should not look at how compensation is*
27 *determined, we do not believe rates paid by ratepayers should include*
28 *costs of a program where an employee has an incentive to perform in a*
29 *manner that could negatively affect the Company's provision of safe,*
30 *reliable utility service at a reasonable rate."* As testified to by Staff
31 *witness Dittmer and set out in Staff's Initial brief, "enhanced earnings*
32 *levels can sometimes be achieved by short-term management decisions*
33 *that may not encourage the development of safe and reliable utility service*

¹² See Attachment RCS-5.

1 *at the lowest long-term cost. ... For example, some maintenance can be*
2 *temporarily deferred, thereby boosting earnings. ... But delaying*
3 *maintenance can lead to safety concerns or higher subsequent 'catch-up'*
4 *costs." [cite omitted] To the extent that Pinnacle West shareholders wish*
5 *to compensate APS management for its enhanced earnings, they may do*
6 *so, but it is not appropriate for the utility's ratepayers to provide such*
7 *incentive and compensation."*
8

9 Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion
10 of that utility's incentive compensation expense, specifically the stock-based
11 compensation.
12

13 **Q. Please summarize Staff's recommendation concerning Southwest's MIP expense.**

14 A. Staff recommends continuing the 50 percent allocation to shareholders ordered for
15 Southwest by the Commission in Decision No. 68487. This results in a reduction to test
16 year expense of \$2,019,268.
17

18 **C-4 Stock-Based Compensation (Other than MIP)**

19 **Q. Please describe Southwest's stock-based compensation plans.**

20 A. Southwest has two stock-based compensation plans: (1) the stock incentive plan ("SIP")
21 and the MIP. The stock-based compensation addressed in Staff Adjustment C-4 is for
22 stock-based compensation other than MIP. As described above, Southwest's MIP
23 incentive compensation also includes a stock-based component.
24

25 **Q. Please describe Southwest's Stock Incentive Plan.**

26 A. Under the SIP, the Company may grant options to purchase shares of common stock to
27 key employees and outside directors. Each option has an exercise price equal to the
28 market price of Company stock on the date of grant and a maximum term of ten years.

1 The options vest 40 percent at the end of year one and 30 percent at the end of years two
2 and three.

3
4 **Q. Did SWG have stock option expense in its prior rate case?**

5 A. No. Prior to 2006, Southwest only recognized compensation expense in its financial
6 statements for restricted shares issued from the MIP. Prior to 2006, Southwest disclosed
7 in its financial statements filed with the Securities and Exchange Commission ("SEC") the
8 effect on net income and earnings per share if the Company had applied the fair value
9 recognition provision of Statement of Financial Accounting Standards No. 123 ("SFAS
10 123") to its stock based-compensation, including both MIP and SIP awards; however,
11 Southwest did not recognize compensation expense for SIP awards. In accordance with
12 changes in financial accounting requirements, such as Statement of Financial Accounting
13 Standards No. 123, as Revised in 2004, (SFAS 123R), Southwest began expensing stock
14 options in 2006, as described in the Company's response to data request STF 10-12 and in
15 an internal Company memo dated December 29, 2005 regarding: "SFAS No. 123
16 (Revised 2004) Share-Based Payment."¹³ Those documents indicate that the provisions of
17 SFAS 123R became effective for the Company in January 2006. Southwest's response to
18 STF 10-12 states that, in May 2007, a restricted stock unit plan replaced Southwest's stock
19 option plan (and were also required to be expensed). Southwest expenses stock-based
20 compensation over a three-year vesting period. Grants to retirement-eligible employees
21 are immediately expensed.

22
23 **Q. Please explain Staff Adjustment C-4.**

24 A. As shown on Schedule C-4, this adjustment decreases test year expense by \$820,915 to
25 reflect the removal of Southwest's stock option compensation expense that is allocated to

¹³ See Attachment RCS-5, pages 33-49 for a copy of SWG's accounting memo concerning this.

1 Arizona operations. The expense of providing stock options and other stock-based
2 compensation to officers and employees beyond their other compensation should be borne
3 by shareholders and not by ratepayers. As noted above, the stock-based compensation
4 addressed in Staff Adjustment C-4 is for stock-based compensation other than MIP.
5

6 **C-5 Supplemental Executive Retirement Plan Expense**

7 **Q. Please explain Staff Adjustment C-5.**

8 A. This adjustment removes 100 percent of the expense for the Supplemental Executive
9 Retirement Plan ("SERP"). The SERP provides supplemental retirement benefits for
10 select executives. Generally, SERPs are implemented for executives to provide retirement
11 benefits that exceed amounts limited in qualified plans by Internal Revenue Service
12 ("IRS") limitations. Companies usually maintain that providing such supplemental
13 retirement benefits to executives is necessary in order to ensure attraction and retention of
14 qualified employees. Typically, SERPs provide for retirement benefits in excess of the
15 limits placed by IRS regulations on pension plan calculations for salaries in excess of
16 specified amounts. IRS restrictions can also limit the Company 401(k) contributions such
17 that the Company 401(k) contribution as a percent of salary may be smaller for a highly
18 paid executive than for other employees.
19

20 **Q. Was Southwest's SERP expense disallowed by the Commission in the Company's**
21 **last rate case?**

22 A. Yes. In Decision No. 68487, February 23, 2006, in the most recent Southwest Gas
23 Corporation rate case, the Commission adopted a recommendation by RUCO to remove
24 SERP expense. In reaching its conclusion regarding SERP, the Commission stated on
25 page 19 of Order 68487 that:
26

1 *"Although we rejected RUCO's arguments on this issue in the Company's*
2 *last rate proceeding, we believe that the record in this case supports a*
3 *finding that the provision of additional compensation to Southwest Gas'*
4 *highest paid employees to remedy a perceived deficiency in retirement*
5 *benefits relative to the Company's other employees is not a reasonable*
6 *expense that should be recovered in rates. Without the SERP, the*
7 *Company's officers still enjoy the same retirement benefits available to*
8 *any other Southwest Gas employee and the attempt to make these*
9 *executives 'whole' in the sense of allowing a greater percentage of*
10 *retirement benefits does not meet the test of reasonableness. If the*
11 *Company wishes to provide additional retirement benefits above the level*
12 *permitted by IRS regulations applicable to all other employees it may do*
13 *so at the expense of its shareholders. However, it is not reasonable to*
14 *place this additional burden on ratepayers."*

15
16 **Q. Was SERP expense also disallowed in the Commission's recent decision in the rate**
17 **case involving UNS Gas, Inc?**

18 **A. Yes, it was. See Decision No. 70011 at pages 27-29. Notably, at page 28 of that Decision,**
19 **the Commission stated:**

20
21 *... the issue is not whether UNS may provide compensation to select*
22 *executives in excess of the retirement limits allowed by the IRS, but*
23 *whether ratepayers should be saddled with costs of executive benefits that*
24 *exceed the treatment allowed for all other employees. If the Company*
25 *chooses to do so, shareholders rather than ratepayers should be*
26 *responsible for the retirement benefits afforded only to those executives.*
27 *We see no reason to depart from the rational on this issue in the most*
28 *recent Southwest Gas rate case [See also Arizona Public Service Co.,*
29 *Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were*
30 *excluded in their entirety.], and we therefore adopt the recommendations*
31 *of Staff and RUCO and disallow the requested SERP costs.*

32
33 **Q. What adjustment related to SWG's SERP expense do you recommend?**

34 **A. I recommend the adjustment to remove SWG's expense for the SERP, which is shown on**
35 **Schedule C-5 and reduces O&M expense by \$1.625 million.**
36

C-6 American Gas Association Dues

Q. Please explain Staff's proposed adjustment for American Gas Association ("AGA") dues.

A. This adjustment is shown on Schedule C-6 and reduces test year expense by \$80,138 to reflect the removal of 40 percent of AGA dues.

Q. How does Staff's proposed adjustment for AGA dues compare with SWG's proposed treatment of such dues?

A. As noted above, Staff's adjustment reflects the removal of 40 percent of AGA core dues, SWG's filing reflected the removal of only 3.39 percent of the AGA dues.

Q. Do you agree with Southwest's adjustment to remove only 3.39 percent of AGA dues?

A. Not entirely. I agree that the marketing and lobbying-related portion of the AGA dues should definitely be removed from rates. I also recognize that in the Southwest Gas rate case, Decision No. 68487, at page 14, after having removed the portion of the AGA dues directly attributable to marketing and lobbying, Southwest Gas was found to have demonstrated that the remainder of the AGA dues should be recoverable as legitimate test year expenses. That Decision also provided a clear directive from the Commission at page 14 of that order stating that: "in its next rate case filing the Company should provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona ratepayers."

1 **Q. What information did Southwest provide concerning the specific benefits of AGA**
2 **activities to the Company and Arizona ratepayers?**

3 A. Southwest witness Randi Aldridge addresses AGA activities in her Direct Testimony at
4 page 12 and pages 21-24. At page 24 she claims that the AGA's efforts provide its
5 members with \$479 million in outright savings or avoided costs in 2006, in comparison
6 with \$18 million in total membership dues. However, she did not provide the source
7 document from which such claimed benefits were taken, and it is not clear whether AGA
8 claimed benefits have ever been independently audited or verified. Her Exhibit RLA-2
9 provides a one-page listing and description of the AGA's functions as listed in the March
10 2005 Annual Audit report to the National Association of Regulatory Utility
11 Commissioners ("NARUC"). However, she did not include the percentage of AGA
12 activities related to each function.

13
14 **Q. Does the information provided by Southwest show that 96.61 percent (100 percent**
15 **minus the Company's 3.39 percent disallowance) of AGA dues-funded activities are**
16 **beneficial to the Company and/or to its Arizona ratepayers?**

17 A. No. Southwest has demonstrated that there is some benefit of AGA membership to the
18 Company and to Arizona ratepayers from some of the AGA's functions. However, the
19 Company has failed to demonstrate that ratepayers should fund activities conducted
20 through an industry organization that would be subject to disallowance if conducted
21 directly by the utility. The Company has failed to demonstrate that a disallowance of
22 AGA dues of only 3.39 percent is adequate. As I will discuss below, other states have
23 used a significantly higher disallowance percentage for gas utility AGA dues than
24 Southwest is proposing here.

25

1 **Q. To your knowledge what percentage disallowance for utility AGA dues has been used**
2 **in other recent utility rate cases?**

3 A. In the recent UNS Gas rate case, as described on pages 32-33 of Decision No. 70011,
4 UNS Gas had initially included \$41,854 for AGA dues, and RUCO witness Moore
5 recommended a partial disallowance of \$1,523, based on an ABA/NARUC Oversight
6 Committee Report indicating that 1.54 percent of AGA dues were for marketing and 2.10
7 percent of dues were for lobbying activities. UNS Gas agreed with that adjustment, and it
8 was ultimately adopted by the Commission. At pages 33-34 of Decision No. 70011,
9 however, the Commission also stated that:

10
11 *Mr. Smith raises a valid point regarding the nature of AGA dues and*
12 *whether a higher percentage of such dues should be disallowed as related*
13 *to activities that are not necessary for the provision of services to UNS*
14 *customers. However, we believe it is reasonable, in this case, to allow*
15 *\$40,311 (\$41,854 - \$1,523), in accordance with RUCO's*
16 *recommendation. As we indicated in the Southwest Gas Order, however,*
17 *we expect UNS in its next rate case to provide more detailed support for*
18 *the allowance of AGA dues and how the AGA's activities benefit the*
19 *Company's customers aside from marketing and lobbying efforts.*

20
21 Since my testimony in that UNS Gas case, I have become aware of AGA dues
22 disallowances made in gas utility rate cases in Michigan and California. In California, it
23 appears that a disallowance of 25 percent of Pacific Gas and Electric Company's AGA
24 dues was made by the Company itself in its filing in Application 05-12-002 (filed 12/2/05)
25 as related to lobbying in the broader sense. In a more recent California rate case,
26 Application No. 06-12-009, involving San Diego Gas and Electric, that utility appears to
27 have proposed a 2 percent AGA dues disallowance for lobbying in the narrowest sense;
28 DRA proposed that the entire cost of SDG&E's AGA dues be excluded; and UCAN

1 supported either the full disallowance or a 25 percent disallowance based on the result
2 from the PG&E rate case and their review of AGA activities information.¹⁴
3

4 In a recent Michigan case involving Consumers Energy Company's gas utility
5 operations¹⁵, that utility conceded to a PSC Staff adjustment to disallow 16.17 percent of
6 the AGA dues. As described in the testimony of MPSC Staff witness Wanda Clavon
7 Jones¹⁶:
8

9 *Staff adjusted dues to eliminate activities that would not be allowed if the*
10 *Company took on those activities for themselves. These activities include*
11 *Public Affairs (15.43%) and Media Communication-Promotion (0.74%).*
12 *Staff obtained the information necessary to make this adjustment from the*
13 *Audit Report on Expenditures of the American Gas Association issued*
14 *June 2001. The total disallowance is 16.17%, or \$60,780. This*
15 *disallowance is consistent with the last rate cases of Consumers,*
16 *MichCon and MGU.*
17

18 **Q. How did you determine the percent disallowance for AGA dues?**

19 A. This was based upon a review of information in the two most recent NARUC sponsored
20 Audit Reports of the Expenditures of the AGA, as well as the components by function of
21 the AGA's 2007 and 2008 budgets. I also relied upon a Florida PSC Staff memorandum,
22 discussed in more detail below, which contained a 40 percent AGA dues disallowance.
23 Copies of relevant pages from the NARUC-sponsored audit reports are provided in
24 Attachment RCS-4. AGA 2007 and 2008 budget information, by component, is
25 summarized on Schedule C-6, page 2.
26

¹⁴ A final order has apparently not been issued yet in the SDG&E rate case, and the parties are apparently working on a settlement.

¹⁵ Michigan PSC Case No. U-13000.

¹⁶ Filed 12/14/2001, at page 6

1 **Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?**

2 A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide
3 regulatory commissions with information that is useful in helping them decide which, if
4 any, of the costs of the association should be approved for inclusion in utility rates. As
5 stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory
6 Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures:
7 “Often, state commissioners review the costs of the association charged or allocated to the
8 utilities in their jurisdiction in accordance with the policies of their commission for
9 treatment of costs directly incurred by the state’s utilities for similar activities.” The
10 NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the
11 aforementioned memo, “these expense categories may be viewed by some State
12 commissions as potential vehicles for charging ratepayers with such costs as lobbying,
13 advocacy or promotional activities which may not be to their benefit.”

14
15 **Q. Have other regulatory commission required similar adjustments to utility-incurred**
16 **AGA dues, based on the results of the NARUC-sponsored audits?**

17 A. Yes. As an example, I have included in Attachment RCS-5, an excerpt from a Florida
18 Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company
19 rate case addressing this issue. As stated in that document:

20
21 *In City Gas's last rate case, In re: Request for rate increase by City Gas*
22 *Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-*
23 *PAA-GU, issued February 5, 2001, the Company removed \$4,045 for AGA*
24 *dues for lobbying. The Commission removed an additional combined*
25 *amount of \$4,970 for memberships, dues and contributions. In re:*
26 *Application for a rate increase by City Gas Company of Florida, Docket*
27 *No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9,*
28 *1994, for interim purposes, the Commission disallowed 40% of AGA dues.*
29 *This order stated that the percentage was based on the 1993 National*
30 *Association of Regulatory Commission's (NARUC) Audit Report on the*
31 *Expenditures of the American Gas Association (Audit Report). Order No.*

1 PSC-94-0957-FOF-GU further stated that this reduction was consistent
2 with adjustments made in rate cases involving other gas companies. In the
3 final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU,
4 issued December 19, 1994, the Commission removed 40.48% of AGA dues
5 "which were related to lobbying and advertising that did not meet the
6 criteria of being informational or educational in nature." In re: Request
7 for rate increase by Florida Division of Chesapeake Utilities Corporation,
8 Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued
9 November 28, 2000, the Commission removed 45.10% of AGA dues.

10
11 The latest NARUC Audit Report on AGA expenditures that Staff was able
12 to locate is dated June, 2001, for the twelve-month period ended
13 December 31, 1999. By a review of the Summary of Expenses, it appears
14 that 41.65% of 1999 AGA expenditures are for lobbying and advertising.
15 Staff has not been able to locate a more recent NARUC Audit Report of
16 the AGA expenditures. However, because approximately 40% appears to
17 have been consistent over a number of years, Staff believes it is not
18 unreasonable to assume that 40% is representative of 2003 and 2004
19 expenditures and recommends that 40% of AGA dues be disallowed in this
20 proceeding.

21
22 From information supplied by the Company, AGA dues were \$39,277 in
23 2003. According to recommendations in Issue 44 and 45, Account 921
24 should be trended on inflation only at 2.0% for 2004. On that basis the
25 2004 amount is \$40,063 ($\$39,277 \times 1.02$). Disallowing 40% would result
26 in disallowing \$16,025 for 2004. The Company's \$2,847 adjustment
27 reduces Staff's adjustment to \$13,178 ($\$16,025 - \$2,847$) for 2004. This
28 position follows past Commission practice of placing charitable
29 contributions and advertising that is not informational or educational in
30 nature below the line.

31
32 Based on the above analysis, Account 921, Office Supplies and Expenses,
33 should be reduced by an additional \$13,178 for AGA membership dues
34 related to charitable contributions and advertising that is not
35 informational or educational in nature.

36
37 The Company is in agreement with this adjustment.
38

1 **Q. What amount of AGA membership dues expense has Staff removed from test year**
2 **expense?**

3 A. As shown on Schedule C-6, Staff has removed \$80,138 in test year expense for AGA
4 membership dues.
5

6 **C-7 Transmission Integrity Management Program**

7 **Q. What is the Transmission Integrity Management Program?**

8 A. The Federal Pipeline Safety Improvement Act of 2002 directed that the Office of Pipeline
9 Safety and the Research and Special Programs Administration divisions of the U.S.
10 Department of Transportation enact regulations that create standards for transmission
11 pipeline risk analysis and adopting a pipeline integrity management program. The
12 Pipeline Safety Improvements Act of 2002 mandated a natural gas Transmission Integrity
13 Management Program ("TRIMP") pursuant to which the industry would undertake a 10-
14 year baseline inspection program to ensure the safety of all gas transmission pipeline
15 segments located in populated areas.
16

17 **Q. Was the TRIMP issue addressed in SWG's last rate case?**

18 A. Yes, the TRIMP issue was addressed in SWG's last rate case and ultimately resulted in a
19 surcharge being implemented that provided for SWG to recover 50 percent of its TRIMP
20 costs via the surcharge.
21

22 **Q. What had SWG requested concerning TRIMP in its last rate case?**

23 A. In its filing in the prior rate case, SWG proposed a pro forma adjustment to recover test
24 year operating expenses related to complying with the Pipeline Safety Improvement Act.
25 The Company's pro forma adjustment in that case was based on projected TRIMP costs

1 using mileage-based estimates of baseline direct assessments, direct examination,
2 maintenance and repairs, and capital replacements during the period 2004 through 2012.
3

4 **Q. What is the significance of the period 2004 through 2012?**

5 A. The 2002 Act regulations required that gas pipeline operators identify transmission lines
6 in high consequence areas ("HCA") and to implement written integrity management
7 programs for these areas. The Office of Pipeline Safety has defined HCA's as areas where
8 the potential consequences of a gas pipeline accident may be significant or may do
9 considerable harm to people and their property. As part of the regulations, the TRIMP
10 was required to, (1) commence baseline assessments by June 17, 2004, (2) complete
11 identification of all HCA's by December 17, 2004, (3) complete at least 50 percent of the
12 baseline assessments of the highest risk pipeline facilities by December 17, 2007, (4)
13 complete baseline assessments for the remaining pipeline facilities by December 17, 2012,
14 and (5) for the remaining life of the facilities, a reassessment of all such facilities must be
15 performed every seven years.
16

17 **Q. What did the Commission order with respect to the TRIMP in SWG's last Arizona**
18 **rate case?**

19 A. In Decision No. 68487, February 23, 2006, the Commission adopted Staff's
20 recommendation that SWG be allowed to recover 50 percent of the TRIMP related costs
21 through a surcharge and balancing account mechanism. Per Staff's recommendation in
22 that case, the surcharge was to have annual adjustments after the first and second years,
23 and terminate at the end of the third year. In addition, in Decision No. 68487, February
24 23, 2006, the Commission stated in part that:

25
26 *With respect to the split of TRIMP costs, we also agree with Staff that*
27 *because the pipeline safety program benefits both shareholders and*

1 *ratepayers, the TRIMP expense should be shared equally. We will*
2 *therefore adopt Staff's recommendation for treatment of TRIMP costs.*

3
4 **Q. How was the TRIMP issue addressed for SWG in the neighboring state regulatory**
5 **jurisdiction of Nevada?**

6 A. In Nevada, Southwest requested and received permission to defer its incremental Nevada
7 TRIMP costs through December 31, 2007 (or the re-setting of rates in its next Nevada rate
8 case, whichever occurred earlier) into a regulatory asset account. Specifically, in
9 September 2004, in Docket No. 04-9012 before the Public Utilities Commission of
10 Nevada, SWG had requested authority to create a regulatory asset to defer recognition of
11 incremental costs associated with SWG's TRIMP until the Company's rates were reset in
12 its next general rate case. SWG proposed to record the TRIMP costs in Account 182.3 -
13 Other Regulatory Assets and in its next general rate case, SWG proposed amortizing the
14 deferred TRIMP costs over the then anticipated period in which the new rates were set.

15
16 The Order issued in the Nevada docket at pages 8 and 9, paragraph 32, referencing
17 Company witness Robert A. Mashas, stated in part that:

18
19 *Mr. Mashas agreed that pursuant to FERC's proposed Accounting Release*
20 *No. 18, TRIMP costs, such as base line assessment and inspection costs,*
21 *should be classified as an operating expense. Mr. Mashas asserted that*
22 *Southwest's proposal complies with this requirement. Southwest is not*
23 *proposing to capitalize the costs but to record the costs in Account No.*
24 *182.3 (Other Regulatory Assets) and to record subsequently those costs as*
25 *an expense when included in rates following the Company's next general*
26 *rate case.*

27
28 In its Order issued March 18, 2005, the Nevada Commission authorized SWG to defer its
29 accrued TRIMP costs, on a going forward basis, upon the effective date of that Order until

1 December 31, 2007, or the effective date of SWG's rates set in its next general rate case,
2 whichever was earlier.

3
4 On page 10, paragraph 37 of its Order in that proceeding, the Nevada commission stated
5 that:

6
7 *In recognition that both ratepayers and shareholders will benefit from the*
8 *new federal regulations and the Company's initial costs of compliance, the*
9 *Commission believes it would be inappropriate to require shareholders to*
10 *bear the full burden of these costs. Therefore, the Commission concludes*
11 *that both ratepayers and shareholders should share in these costs.*

12
13 In addition, on page 10, paragraph 38 of that Order, the Nevada commission stated:

14
15 *In an effort to balance the cost burden between ratepayers and*
16 *shareholders, the Commission finds that Southwest's request for authority*
17 *to defer the TRIMP costs, that is Southwest's base line assessment and*
18 *inspection costs, is justified. The Commission, however, recognizes that*
19 *the benefits for shareholders will increase over time. Consequently, the*
20 *Commission finds that Southwest's authority to defer its TRIMP costs*
21 *should terminate upon the effective date of new Company rates following*
22 *Southwest's next general rate case or December 31, 2007, whichever is*
23 *earlier.*

24
25 **Q. Since the Company's authorization to defer TRIMP costs in Nevada expired on**
26 **December 31, 2007, what accounting treatment is SWG currently applying to its**
27 **Nevada TRIMP costs?**

28 **A.** SWG indicated through informal discussions that the Company has been expensing its
29 TRIMP costs related to its Nevada operations as of January 1, 2008. This understanding
30 of how SWG was to account for its TRIMP costs after December 31, 2007, i.e., that SWG
31 was no longer authorized to defer its Nevada TRIMP costs after that date, was confirmed
32 via informal discussions with the Nevada Staff.

1 **Q. Under the current DOT TRIMP surcharge mechanism, how are the Arizona-related**
2 **TRIMP expenses and surcharge revenues reflected on SWG's books?**

3 A. According to Mr. Mashas' Direct Testimony, at page 19, SWG currently charges the 50
4 percent of TRIMP cost (i.e., the 50 percent, per Decision No. 64687, that is chargeable to
5 its Arizona ratepayers) to Account 182.3, Regulatory Assets. According to the
6 Company's response to data request STF-9-18, SWG records the DOT TRIMP surcharge
7 revenue as a credit to Account 182.3.¹⁷ As SWG records credits to Account 182.3 for
8 DOT TRIMP surcharge revenues received, the Company debits Account 407.3,
9 Regulatory Amortizations, for a like amount.

10
11 SWG expenses the remaining 50 percent of TRIMP cost (i.e., the portion pursuant to
12 Decision No. 68487 that is to be borne by shareholders) to Account 887, Maintenance of
13 Mains.

14
15 **Q. What is the Company proposing for TRIMP costs in the instant proceeding?**

16 A. Southwest proposes to cease charging TRIMP related costs to Account 182.3 in the month
17 that the new rates in the instant proceeding take effect. In addition, Mr. Mashas also states
18 that the surcharge will discontinue once the deferred balance in Account 182.3 reaches
19 zero. Page 19 of Mr. Mashas' testimony, lines 3-12, states that:

20
21 *The TRIMP related surcharge revenue recorded during the test year is not*
22 *included in the revenue at present rates, therefore, it is appropriate to*
23 *remove the related expense. In addition, the Company proposes to*
24 *discontinue recovering 50 percent of TRIMP cost through a surcharge and*
25 *to recover the test year TRIMP-related expense in Account 887 in base*
26 *rates. Adjustment No. 9 removes the TRIMP cost recorded in Account*
27 *407.3 and transfers it to Account 887.*

28

¹⁷ See Attachment RCS-5.

1 **Q. What comprises the TRIMP related portion of Company Adjustment No. 9?**

2 A. The TRIMP related portion of SWG's Adjustment No. 9 is comprised of two parts.

3
4 During the test year, SWG recorded \$551,530 in Account 407.3 for Amortization of
5 Regulatory Debits. The first part of SWG Adjustment No. 9 removes \$551,530 from
6 Account 407.3 - Regulatory Debits. The second footnote on SWG's Adjustment No. 9
7 states that: "Since the Company is not including the offsetting revenue at present rates, the
8 expense is being removed with this adjustment."

9
10 The second part of the TRIMP related portion of SWG's Adjustment No. 9 includes test
11 year TRIMP costs of \$920,914 that were recorded in Account 182.3 - Other Regulatory
12 Assets into an expense account, so this effectively becomes SWG's requested amount of
13 operating expense for TRIMP. The third footnote on SWG's Adjustment No. 9 states that:
14 "TRIMP costs were deferred to Account 182.3, and 50 percent of these costs were
15 recovered through a surcharge per Decision No. 68487." From the \$920,914, of test year
16 TRIMP cost, the Company subtracted the amount of \$348,690. The fourth footnote on
17 SWG's Adjustment No. 9 states that: "Disallowed TRIMP costs were written off to
18 Account 887. There is a one month lag between the transaction posting date and the
19 write-off date." SWG increased O&M expense by the net amount of \$572,224. The fifth
20 footnote on SWG's Adjustment No. 9 states that: "Southwest is requesting to recover its
21 ongoing non-capital related incremental TRIMP costs in base rates, based on test year
22 expenditures, and to discontinue the TRIMP surcharge."

23
24 The net result of these adjustments is that SWG is requesting an operating expense
25 allowance of \$920,914 for TRIMP.

1 **Q. Have you summarized on a Schedule the TRIMP costs that SWG has incurred for its**
2 **Arizona operations for the initial five-year period?**

3 A. Yes. This is shown on Attachment RCS-2, Schedule C-7, page 2. SWG began incurring
4 TRIMP cost for Arizona in May 2004. As summarized on that schedule and in a more
5 condensed form, in the table below, for the initial five-year TRIMP period of 2003-2007,
6 SWG incurred a total of \$4,677,860:

7
8 Summary of SWG Arizona TRIMP Costs
First Five Year TRIMP Period, 2003-2007

Year	Amount	Percent
2003	\$ -	0.00%
2004	\$ 414,227	8.86%
2005	\$ 816,633	17.46%
2006	\$ 700,837	14.98%
2007	\$ 2,746,162	58.71%
Total	\$ 4,677,860	100.00%

Average	\$ 935,572	
---------	------------	--

13
14
15 On average, SWG incurred approximately \$935,000 of Arizona TRIMP cost per year.
16 However, SWG incurred the majority of this cost, \$2,746,162, or 58.71 percent, in the
17 final year, 2007, of the initial five-year TRIMP period.

18
19 **Q. Why has SWG stated that it should be allowed to prospectively recover 100 percent**
20 **of its TRIMP related costs?**

21 A. Mr. Mashas states on page 20 of his Direct Testimony that SWG is unaware of any other
22 gas utilities in the nation, subject to the Federal Pipeline Safety Improvement Act of 2002,
23 that are not recovering 100 percent of prudently incurred cost of compliance with the Act.
24 Therefore, SWG believes it is fair and reasonable that 100 percent of the test year
25 recorded TRIMP related costs be recovered in base rates.
26

1 **Q. What is Staff's recommendation with regard to the TRIMP issue in the instant**
2 **proceeding?**

3 **A. Staff recommends that:**

4
5 1) The current TRIMP deferral and surcharge mechanism that was ordered by the
6 Commission in Decision No. 68487 for a 36-month period will continue for the remainder
7 of the 36-month period. This surcharge, which Southwest has indicated it will be updating
8 in the near future, would continue the 50/50 sharing ordered by the Commission in
9 Decision No. 68487. Any over- or under-recovery of the 50 percent of TRIMP costs as of
10 February 28, 2009 (the end of the 36-month period), would be addressed in the TRIMP
11 surcharge for the subsequent period.

12
13 2) After the TRIMP surcharge ordered by the Commission in Decision No. 68487 is
14 completed (which is currently expected to occur by February 28, 2009), a new TRIMP
15 surcharge would replace it. The new TRIMP surcharge would be designed to recover
16 \$921,000 of TRIMP costs over the initial twelve-month period (currently expected to be
17 March 2009 through February 2010). Providing for an annual recovery of \$921,000 of
18 TRIMP costs, divided by a test year rate case volume of 743,110,918 therms would
19 produce a DOT TRIMP surcharge of \$0.00124 per therm. TRIMP surcharge revenue and
20 TRIMP costs would be recorded by Southwest into Account 182.3. Starting with the
21 March 2009 TRIMP surcharge period, the 50 percent shareholder responsibility for
22 TRIMP costs would cease.

23
24 3) The TRIMP revenue and costs in Southwest's base rate filing would be removed, since
25 prospective recovery would continue to be governed by the existing and the replacement
26 TRIMP surcharge mechanisms, described above.

1 **Q. Please explain Staff Adjustment C-7.**

2 A. As shown on Schedule C-7, page 1, this adjustment reduces Southwest's proposed test
3 year expenses by \$920,914, to reflect a continuation of the surcharge treatment for TRIMP
4 established by the Commission in Southwest's last rate case, and the prospective
5 continuation of TRIMP cost recovery via a replacement surcharge, as described above,
6 commencing in March 2009, after the surcharge ordered by the Commission in Decision
7 No. 68487 for 36 months is completed.
8

9 **Q. What is the estimated replacement TRIMP surcharge for March 2009 forward?**

10 A. As shown on Schedule C-7, page 3, providing for an annual recovery of \$921,000 of
11 TRIMP costs, divided by a test year rate case volume of 743,110,918 therms would
12 produce a TRIMP surcharge of \$0.00124 per therm.
13

14 **Q. Why has Staff not applied a 50/50 sharing of TRIMP costs beyond the initial 36-**
15 **month period of the TRIMP surcharge ordered by the Commission in Decision No.**
16 **68487?**

17 A. There does not appear to be a compelling reason for continuing the 50/50 sharing of
18 Southwest's TRIMP costs prospectively beyond the initial 36-month surcharge period
19 ordered by the Commission in Decision No. 68487. Southwest has indicated that it is not
20 aware of any other gas distribution utilities for which shareholder sharing of TRIMP costs
21 has been required. Staff is not aware of any either. As described above, TRIMP is a
22 federally mandated pipeline inspection and safety program. TRIMP costs are being
23 incurred not only by Southwest Gas, but also by all other affected gas distribution utilities.
24 The sharing of TRIMP costs was not an issue in the recent UNS Gas rate case. Based on
25 consideration of factors such as these, Staff recommends that the 50 percent shareholder

1 responsibility for TRIMP costs ordered in Decision No. 68487 not continue beyond the
2 end of the 36-month surcharge period ordered by the Commission in that Decision.
3

4 **Q. Why does Staff recommend that SWG's TRIMP costs continue to be addressed in a**
5 **surcharge, as opposed to some other ratemaking treatment, such as a normalized**
6 **O&M expense?**

7 A. Staff recommends that SWG's TRIMP costs continue to be addressed in a surcharge for
8 the following reasons. First, a TRIMP surcharge is already in place. Customers are used
9 to seeing the TRIMP surcharge (i.e., the DOT Pipeline Safety Surcharge) on their bills.
10 Second, TRIMP is an on-going program, and has been federally mandated. Thus,
11 continuation of the surcharge to recover these federally-imposed costs would be
12 appropriate. Third, within the second five-year TRIMP period, which runs from 2008
13 through 2012, SWG has significant discretion as to the timing of when it will conduct the
14 pipe inspections and incur costs. As noted above, in the first five-year TRIMP period,
15 2003 through 2007, SWG incurred almost 60 percent of its total costs in the fifth and final
16 year, 2007. A surcharge mechanism for TRIMP cost recovery would thus help assure that
17 Southwest recovers no more, and no less than, its actual costs. It would therefore
18 discourage "gaming" of the timing of such costs, whereby incurrence of such costs could
19 potentially be delayed and concentrated into a test year period in SWG's next rate case.
20 Based on reasons such as these, Staff concludes that there is merit in continuing to address
21 the recovery by SWG of its Arizona TRIMP costs via a surcharge mechanism.
22

C-8 A&G Expenses – Annualized Paiute Allocation

Q. Please explain Staff Adjustment C-8.

A. This adjustment decreases administrative and general expenses by \$23,447 for a correction to the annualized Paiute allocation, per Southwest's response to data request STF-1-53.¹⁸

C-9 Interest on Customer Deposits

Q. Please explain Staff Adjustment C-9.

A. This adjustment increases expense by \$148,852 for interest on Customer Deposits. The same 6 percent interest rate used by Southwest in its Adjustment No. 16 was applied to the amount of Staff's rate base adjustment for Customer Deposits (Staff Adjustment B-4).

C-10 Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-10. This adjustment increases income tax expense by the amount shown on Schedule C-10 and decreases the Company's achieved operating income by a similar amount.

¹⁸ See Attachment RCS-5.

C-11 Flow-back of Excess Deferred Taxes

Q. Please explain your adjustment to flow-back excess deferred taxes.

A. This adjustment reduces federal income tax expense by \$147,345 to flow back excess deferred federal income taxes over a three-year period. The three-year period used is the same period Southwest has used in this case to normalize the allowance for rate case expense.

Q. What amount of excess deferred taxes does Southwest have?

A. Southwest has on its books as of December 31, 2007, approximately \$442,000 of excess deferred taxes relating to the Arizona jurisdiction.

Q. What does that balance represent?

A. This balance represents deferred federal income taxes that were recorded in prior years at federal income tax ("FIT") rates higher the current 35 percent FIT rate. When the tax-timing differences related to this reversed, Southwest flowed the tax effect back at the 35 percent FIT rate, rather than at the higher FIT rate that was used to originally compute the charge to deferred income tax expense.

Q. Deferred taxes can be a complicated area. Can you please provide a simplified example to help us understand?

A. Certainly. To provide a simple illustration of this concept, assume that there was a \$1,000 depreciation related tax timing difference in a prior year, where the tax deduction exceeded the book expense by the \$1 million. Assume that the FIT rate at the time when the deferred tax relating to this was originally recorded was 46 percent. In this simplified illustration, Southwest would have charged (debited) Deferred Federal Income Tax Expense by \$460,000 and credited (increased) Accumulated Deferred Income Taxes by

1 \$460,000. In this example, the \$460,000 Deferred Federal Income Tax Expense would
2 have been paid for by ratepayers, and the \$460,000 ADIT amount would become an offset
3 to rate base.

4
5 Over the life of a unit of utility plant, the annual timing differences between tax
6 deductions and book expense will eventually zero out. In the immediate years following
7 the addition of new plant, it would be typical for the related tax depreciation to exceed the
8 corresponding book depreciation. In later years, however, and especially after the plant
9 has been fully depreciated for tax purposes, the book depreciation expense would typically
10 exceed the deduction for tax depreciation related to that item of plant.

11
12 When the book depreciation expense begins to exceed the tax deduction, the previous
13 “timing differences” (where the tax deduction exceeded the book expense) are said to
14 “turn around.” During the “turn around” period, the typical accounting entries would be
15 to credit (i.e., reduce) Deferred Income Tax Expense and to debit (reduce) the ADIT
16 balance. Since the ADIT balance in our simplified example had been built up using a 46
17 percent FIT rate, the “turn around” should have flowed-back the tax effects using the same
18 46 percent FIT rate. When the FIT rate was reduced, Southwest would have “excess”
19 deferred taxes on its books. Additionally, if Southwest had used a 35 percent FIT rate to
20 flow back the ADIT that had been accrued using a higher FIT rate, then Southwest would
21 continue to have “excess” ADIT on its books.

22
23 In this simple illustrative example, the excess would be the difference in the tax rates used
24 to set up and flow-back the ADIT (i.e., 11 percent, based on the difference in the 46
25 percent and 35 percent FIT rates) times the \$1 million timing difference. In this example,
26 the amount of “excess” deferred income taxes would be \$110,000. This result has

1 occurred because these deferred taxes should have been reversed at their originating FIT
2 rates, but were instead reversed at an FIT rate of 35 percent.

3
4 **Q. Did Southwest maintain the excess deferred taxes in the ADIT account?**

5 A. No. Southwest transferred the excess deferred taxes out of the ADIT account, and into an
6 Income Tax Reserve account.

7
8 **Q. What is the ratemaking consequence of Southwest's removal of the excess deferred
9 taxes from the ADIT account?**

10 A. While the excess deferred taxes were in the ADIT account (Account 282), they were an
11 offset to utility rate base. Southwest has not reduced rate base by the credit balance in the
12 Income Tax Reserve account.

13
14 **Q. Why has Southwest maintained the excess deferred taxes on its books in a liability
15 account?**

16 A. The primary reason appears to be regulatory uncertainty as to the ultimate disposition of
17 the excess taxes. Southwest provided a confidential tax memo¹⁹ which stated as follows:

18
19 REDACTED.

20
21 **Q. What regulatory treatment does Staff recommend for the excess deferred taxes
22 remaining on Southwest's books in a liability account that relate to Arizona utility
23 operations?**

24 A. I recommend that these excess deferred taxes be flowed back to Southwest's Arizona
25 ratepayers over three years, which is the Company's assumed rate case filing interval that

¹⁹ A copy of Southwest's confidential tax memo is provided in Attachment RCS-6.

1 the Company used to normalize rate case expense in the current rate case. This proposed
2 regulatory treatment would reduce income tax expense in the current rate case by
3 \$147,345. The liability balance for the excess deferred income taxes relating to Arizona
4 utility operations would be reduced to zero by the time of Southwest's next Arizona rate
5 case, assuming the Company's filing occurs at the 3 year filing interval being assumed in
6 the current case for rate case expense normalization purposes.

7
8 **Q. What would likely happen to the excess deferred income taxes relating to**
9 **Southwest's Arizona gas utility operations, if this adjustment is not made?**

10 A. If this adjustment is not made, it appears likely that the excess deferred income taxes
11 relating to Southwest's Arizona gas utility operations, would be reported as shareholder
12 income, shortly after a final order by the Commission in this rate case. This would likely
13 occur because, if the adjustment recommended by Staff were not made, the substantial
14 regulatory uncertainty existing currently as to whether these excess taxes had to be
15 returned to Arizona ratepayers in the form of a reduced income tax expense, would have
16 been resolved in favor of the Company's shareholders.

17
18 **Q. Are you also recommending a rate base deduction for the unamortized balance of**
19 **Arizona related excess deferred taxes?**

20 A. No. While a rate base deduction for the excess deferred tax liability balance might be
21 theoretically justified, since the excess deferred taxes represent a form of cost-free capital
22 to the utility, I am not recommending such treatment in the current case for the following
23 rather practical reasons. First, the remaining balance of excess deferred income taxes is
24 relatively insignificant with respect to Southwest's total rate base.²⁰ Second, by flowing
25 back the excess deferred income taxes as a reduction to expense, but not making a

²⁰ For example, a rate base deduction of \$442,000 on a total rate base of \$1.095 billion is about 0.04 percent, i.e., 4/100ths of 1 percent.

1 corresponding adjustment to rate base, this achieves a form of balancing of the interests of
2 ratepayers and shareholders in reasonably disposing of an item that had been the subject of
3 some regulatory uncertainty.

4
5 **C-12 Injuries and Damages**

6 **Q. Please explain your adjustment for Injuries and Damages expense.**

7 A. This adjustment is shown on Schedule C-12, and reduces Southwest's proposed expense
8 for Injuries and Damages in Account 925 by \$861,717. As shown on Schedule C-12, page
9 1, in column A, on line 18, during the test year, Southwest recorded an expense for
10 Injuries and Damages of \$5.679 million for Arizona. As shown in Column B of that
11 Schedule, Southwest's filing included three pro forma adjustments that attempted to
12 increase this expense to \$8.169 million, for an increase of approximately \$2.490 million.
13 That is an increase of approximately 44 percent.

14
15 In response to various Staff data requests, SWG identified errors in its filed calculation.
16 Southwest now proposes a pro forma Injuries and Damages expense for Arizona of \$8.259
17 million, as shown on Schedule C-12, page 1, column C, line 18. This represents an
18 increase of \$2.580 million or 45 percent, over the test year recorded amount.

19
20 In contrast with SWG's proposals, as shown on Schedule C-12, page 1, column D, line 18,
21 Staff recommends a normalized allowance for Injuries and Damages expense for Arizona
22 of \$7.307 million. This represents an increase of \$1.628 million or 29 percent, over the
23 test year recorded amount.

24
25 Staff's recommended allowance for Injuries and Damages expense in Account 925 is
26 \$861,717 lower than the pro forma adjusted amount in SWG's original filing. The

1 \$861,717 reduction to SWG's original proposed pro forma adjusted amount is shown on
2 Schedule C-12, page 1, columns D and E.

3
4 **Q. Please explain the major differences between Staff's and the Company's**
5 **recommended Injuries and Damages expense.**

6 A. The major differences between Staff's and the Company's recommended Injuries and
7 Damages expense can be attributed to the reserve for self-insurance component of this
8 expense. As shown on Schedule C-12, page 1, line 2, Staff has increased SWG's recorded
9 Arizona Direct amount for the reserve for self-insurance by \$1,378,765. As shown on
10 Schedule C-12, page 2, column E, Staff proposes a normalized annual amount for the
11 Arizona Direct reserve for self insurance of \$820,000. This compares with Southwest's
12 recorded test year amount of negative \$558,765, and with Southwest's proposed corrected
13 amount of negative \$858,765. Staff's proposed normalized amount for Arizona Direct
14 reserve for self insurance is supported by the ten-year average, which, as shown on
15 Schedule C-12, page 2, columns A and C, line 12, is \$817,741.²¹

16
17 Southwest also has a "common" reserve for self-insurance that is allocated to all of its
18 operations. Because of a May 2005 leaking gas line fire, for which Southwest incurred an
19 abnormal and extremely high payment to settle the related litigation, even the ten-year
20 average for the "common" reserve for self-insurance expense is not representative.
21 Ratepayers should pay for a normalized level of insurance expense, but should not be
22 required to pay for extremely high litigation payments that the utility incurred related to

²¹ The ten-year average for Arizona Direct self insurance was derived from SWG's response to data request STF-6-60, which included 2007 information through November. Southwest supplemented its response to STF-6-60 to include 2007 information through December. Due to the timing of receipt of the supplemental response, Staff's adjustment only reflects the 2007 information through November. See Attachment RCS-5 for copies of the original and supplemental responses. Reflecting the supplemental information would decrease Staff's adjustment by approximately \$10,000. The effect of this supplemental information will be incorporated into Staff's revenue requirement, if necessary, when Staff files its surrebuttal testimony.

1 the May 2005 leaking gas line fire. Consequently, as shown on Schedule C-12, page 2,
2 column F, I used a \$200,000 annual allowance for the "common" reserve for self-
3 insurance expense. The \$200,000 equals the Company's recorded amount in 2006, as well
4 as 2002. As one can see from the annual amounts listed on Schedule C-12, columns B
5 and D, the annual expense rates from a negative \$300,000 in 2003, to a positive \$500,000
6 in 1998, with the \$10.367 million in 2005 relating to the May 2005 leaking gas line fire
7 (listed for 2005 in Column B) being an extreme anomaly in comparison with all of the
8 other amounts. It compares with the ten-year average of \$74,950 shown on Schedule C-
9 12, page 2, column D, which is without the massive impact of the May 2005 leaking gas
10 line fire litigation settlement.

11
12 **Q. Please explain why Southwest's Arizona ratepayers should not be responsible for the**
13 **impact on Injuries and Damages expense relating to the Company's settlement of**
14 **litigation related to the May 2005 leaking gas line fire.**

15 A. Arizona ratepayers should not be responsible for the massive expense incurred by the
16 Company to settle litigation related to the May 2005 leaking gas line fire for at least two
17 reasons. That expense is abnormal and was incurred in a prior period. Rates in the
18 current case are being established for prospective application. While historical
19 information may be useful to address normalized expenses, an extremely abnormal event
20 like the May 2005 leaking gas line fire-related settlement expense, is not expected to
21 reoccur and should therefore not be built into pro forma operating expenses. Second, the
22 Company has not demonstrated that the May 2005 leaking gas line fire was not due to its
23 own negligence. Ratepayers should not be burdened with extra costs that may have been
24 incurred as the result of negligence by the utility.

25

1 **Q. Please explain the other information shown on Schedule C-12, page 2.**

2 A. Lines 17-19 show a derivation of the adjustment to Southwest's proposed reserve for self-
3 insurance expense, as filed, under three scenarios: (1) using a 10-year average, without
4 adjustment for the May 2005 leaking gas line fire; (2) using a 10-year average, with the
5 extreme and abnormal amount of over \$10 million related to the May 2005 leaking gas
6 line fire removed; and (3) using normalized self-insurance expense of \$820,000 for
7 Arizona Direct and \$200,000 for common allocated. Line 19 shows the approximate net
8 adjustment to Southwest's as-filed pro forma expense, under each of the above.
9 Lines 20-22 present similar information, with the frame of reference being Southwest's
10 proposed revised expense for self-insurance. Line 22 shows the approximate net
11 adjustment to Southwest's proposed revised pro forma expense, under each of the above
12 scenarios.

13
14 **Q. Please summarize Staff's adjustment for Injuries and Damages Expense.**

15 A. As shown on Schedule C-12, page 1, Southwest's as-filed pro forma expense for Injuries
16 and Damages (Account 925) should be reduced by \$861,717.

17
18 **C-13 Leased Aircraft Operating Costs**

19 **Q. Please explain your adjustment for Leased Aircraft Operating Costs.**

20 A. This adjustment normalizes the expense for Southwest's leased aircraft operating costs.
21 Southwest does not own aircraft, but does lease aircraft for its business operations. The
22 expense for the test year is higher than for any year in the four-year period, 2004 through
23 2007. As shown on Schedule C-13, the test year expense for leased aircraft is adjusted
24 downward by \$32,814 to a normalized amount based on the four-year period, 2004
25 through 2007.

26

C-14 El Paso Pipeline Rate Case Litigation Cost

Q. Please explain your adjustment for El Paso Pipeline Rate Case Litigation Cost.

A. The Company's recorded expense for El Paso Pipeline Litigation allocated to Arizona operations of \$854,889, is higher than the amount in any year, 2005, 2006 or 2007, and appears to contain expense for a period when the cost for such litigation was at its peak. In comparison with the test year Arizona Direct amount expense of \$843,038, the comparable Arizona Direct expense for was \$117,761 for 2005; \$800,809 for 2006; and \$167,675 for 2007. Additionally, Southwest's response to data request STF-10-1 lists zero expense for this in 2004.²² As shown on Schedule C-14, the abnormally high test year expense for the El Paso Pipeline Rate Case Litigation is adjusted downward by \$477,415, to a normalized level, based on the average for 2005 through 2007.

C-15 Annualized Amortization for New Intangible Plant

Q. Please explain Staff's adjustment for the annualized amortization for new intangible plant that was placed into service by December 31, 2007.

A. Southwest's filing included an adjustment (Company Adjustment No. 14) to add to test year amortization expense \$565,333 for the annualized amortization on new intangible plant that the Company projected would be placed into service by December 31, 2007. As noted above, Staff has made a related adjustment to rate base in Staff Adjustment B-6. Staff Adjustment C-15 adjusts the Company's estimated amounts. As shown on Schedule C-15, to reflect actual new intangible plant that was placed into service by December 31, 2007, the estimated annualized amortization for new Intangible Plant allocated to Arizona that had been reflected in Southwest's filing is reduced by \$181,069.

²² See Attachment RCS-5.

- 1 **Q. Does this conclude your testimony?**
- 2 **A. Yes, it does.**

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Washington, Washington, D.C., Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company (Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company - Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company - Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company - Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA	
& 76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA	
& 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001	
& ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU	
& 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities
T E-1032-88-102	Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona
& U-1551-89-103	Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and	Intrastate Access Charge Methodology, Pool and Rates
TC-91-040B	Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS &	General Development Utilities - Port Malabar and
911-67-WS	West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314	Metropolitan Edison Company (Pennsylvania PUC)
& M-920313C006	Pennsylvania American Water Company (Pennsylvania PUC)
R00922428	
E-1032-92-083 &	
U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 &	Citizens Utilities Company - Gas Division
U-1032-93-193	(Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/	Sale of Assets CC&N from Contel of the West, Inc. to
E-1032-93-169	Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed	Citizens Utility Company - Arizona Telephone Operations
Staff Investigation	(Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non- Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power & Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed	Delaware - Estimate Impact of Universal Services Issues
Staff Investigation	(Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60,	Investigation of 1998 Intrastate Access charge filings
U-98-65, U-98-67	(Alaska PUC)
(U-99-66, U-99-65,	Investigation of 1999 Intrastate Access Charge filing
U-99-56, U-99-52)	(Alaska PUC)
Phase II of 97-SCCC-149-GIT	
	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed	Village of University Park, IL - Valuation of Water and
Project	Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC)
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery
	Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No.	
98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR
	Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016,	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)

Southwest Gas Corporation
Docket No. G-01551A-07-0504

Attachment RCS-2
Staff Accounting Schedules

Accompanying the Surrebuttal Testimony of Ralph C. Smith

Schedule	Description	Pages
	Revenue Requirement Summary Schedules	
A	Calculation of Revenue Deficiency (Sufficiency)	1
A-1	Gross Revenue Conversion Factor	1
B	Adjusted Rate Base	1
B.1	Summary of Rate Base Adjustments	2
C	Adjusted Net Operating Income	1
C.1	Summary of Net Operating Income Adjustments	3
D	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
B-1	Yuma Manors Pipe Replacement	1
B-2	Customer Advances for Construction	2
B-3	Cash Working Capital	1
B-4	Customer Deposits	3
B-5	Accumulated Deferred Income Taxes - Acct.190	2
B-6	Intangible Plant Added After the Test Year	1
B-7	Accumulated Deferred Income Taxes - RCND	1
	Net Operating Income Adjustments	
C-1	Yuma Manors Depreciation and Property Tax Expense	2
C-2	Gain on Sale of Utility Property	1
C-3	Management Incentive Program	1
C-4	Stock Based Compensation	1
C-5	Supplemental Executive Retirement Expense	1
C-6	American Gas Association Dues	1
C-7	TRIMP Surcharge	3
C-8	A&G Expenses - Annualized Paiute Allocation	1
C-9	Interest on Customer Deposits	1
C-10	Interest Synchronization	1
C-11	Flow Back Excess Deferred Income Taxes	1
C-12	Injuries and Damages	2
C-13	Leased Aircraft Operating Costs	1
C-14	El Paso Natural Gas Rate Case Expense	1
C-15	New Intangible Plant Annualized Amortizations	1
	Total Pages	41

Southwest Gas Corporation
Computation of Increase in Gross Revenue Requirement

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Schedule A
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Reference	SWG Proposed		Staff Proposed		
			Original Cost (A)	Fair Value (B)	Original Cost (C)	Fair Value Option 1 (D)	Fair Value Option 2 (E)
1	Adjusted Rate Base	Sch. B	\$ 1,094,790,047	\$ 1,469,135,559	\$ 1,070,195,857	\$ 1,393,347,942	\$ 1,393,347,942
2	Rate of Return	Sch. D	9.45%	7.04%	8.88%	6.80%	7.09%
3	Operating Income Required		\$ 103,457,659	\$ 103,457,659	\$ 95,085,703	\$ 94,747,660	\$ 98,788,369
4	Net Operating Income Available	Sch. C	\$ 73,180,098	\$ 73,180,098	\$ 77,260,450	\$ 77,260,450	\$ 77,260,450
5	Operating Income Excess/Deficiency		\$ 30,277,561	\$ 30,277,561	\$ 17,825,253	\$ 17,487,210	\$ 21,527,919
6	Gross Revenue Conversion Factor	Sch. A-1	1.6586	1.6586	1.6586	1.6586	1.6586
7	Overall Revenue Requirement		\$ 50,218,363	\$ 50,218,363	\$ 29,564,965	\$ 29,004,287	\$ 35,706,207

Notes and Source

Cols. A & B taken from SWG filing, Schedule A-1

Southwest Gas Corporation
Computation of Gross Revenue Conversion Factor

Test Year Ended April 30, 2007

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Schedule A-1
Page 1 of 1

Line No.	Description	Rate (A)	Company Proposed (B)	Staff Proposed (C)
1	Gross Revenue		1.0000000	1.0000000
2	Less: Uncollectible Revenue		0.0029890	0.0029890
3	State Taxable Income		0.9970110	0.9970110
4	Less: State Income Taxes	6.9680%	0.0694720	0.0694720
5	Federal Taxable Income		0.9275390	0.9275390
6	Federal Income Tax	35.0000%	0.3246390	0.3246390
7	Change in Net Operating Income		0.6029000	0.6029000
8	Gross Revenue Conversion Factor		1.6586	1.6586

Notes and Source

Cols. A&B: SWG Filing, Schedule C-3

Components of Revenue Requirement Increase	
	Amount
9 Net Income	\$ 17,824,717
10 Federal and State Income Taxes	\$ 11,651,878
11 Uncollectibles	\$ 88,370
12 Total Revenue Increase	\$ 29,564,965
13 Computation of State and Federal Income Tax Rate	L. 10 / L. 3
14 Per SWG Schedule C-3, page 2 of 2	39.5293%
	39.5292%

Line No.	Description	Original Cost			RCND		
		As Adjusted by SWG (A)	Staff Adjustments (B)	As Adjusted by Staff (C)	As Adjusted by SWG (D)	Staff Adjustments (E)	As Adjusted by Staff (F)
1	Gross Utility Plant in Service	\$ 2,053,847,890	\$ (1,774,972)	\$ 2,052,072,918	\$ 3,224,193,614	\$ (1,772,667)	\$ 3,222,420,947
2	Less: Accumulated Depreciation	\$ (752,275,563)	\$ 139,314	\$ (752,136,249)	\$ (1,173,930,265)	\$ 137,009	\$ (1,173,793,256)
3	Net Utility Plant in Service	\$ 1,301,572,327	\$ (1,635,658)	\$ 1,299,936,669	\$ 2,050,263,349	\$ (1,635,658)	\$ 2,048,627,691
4	Customer Advances for Construction	\$ (37,910,017)	\$ (11,284,772)	\$ (49,194,789)	\$ (37,910,017)	\$ (11,284,772)	\$ (49,194,789)
5	Customer Deposits	\$ (31,921,898)	\$ (2,480,873)	\$ (34,402,771)	\$ (31,921,898)	\$ (2,480,873)	\$ (34,402,771)
6	Accumulated Deferred Income Taxes	\$ (142,632,297)	\$ (9,246,678)	\$ (151,878,975)	\$ (142,632,297)	\$ (111,633,530)	\$ (254,265,827)
7	Total Deductions	\$ (212,464,212)	\$ (23,012,323)	\$ (235,476,535)	\$ (212,464,212)	\$ (125,399,175)	\$ (337,863,387)
8	Allowance for Working Capital	\$ 5,681,932	\$ 53,791	\$ 5,735,723	\$ 5,681,932	\$ 53,791	\$ 5,735,723
9	Total Rate Base	\$ 1,094,790,047	\$ (24,594,190)	\$ 1,070,195,857	\$ 1,843,481,069	\$ (126,981,042)	\$ 1,716,500,027

Notes and Source

Cols. A and D: SWG filing, Schedule B

Fair Value Calculation (Per Company)

Original Cost	\$ 1,094,790,047
RCND	\$ 1,843,481,069
Total	\$ 2,938,271,116
Average (Fair Value)	\$ 1,469,135,559
	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	\$ 1,070,195,857
RCND	\$ 1,716,500,027
Total	\$ 2,786,695,884
Average (Fair Value)	\$ 1,393,347,942
	See Sch. A

Southwest Gas Corporation
Summary of Rate Base Adjustments
Original Cost
Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule B.1 (OCRB)
Page 1 of 1

Line No.	Description	Staff Adjustments	Yuma Manors		Customer Advances for Construction	Cash Working Capital	Customer Deposits	Accumulated Deferred Income Taxes - Acct. 190	Intangible Plant		Accumulated Deferred Income Taxes - RCND	
			Replacement B-1	Pipe B-2					Added After the Test Year	B-6	B-5	B-7
1	Gross Utility Plant in Service	\$ (1,774,972)	\$ (1,231,762)							\$ (543,210)		
2	Less: Accumulated Depreciation	\$ 139,314	\$ 139,314									
3	Net Utility Plant in Service	\$ (1,635,658)	\$ (1,092,448)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (543,210)	\$ -		
4	Customer Advances for Construction	\$ (11,284,772)		\$ (11,284,772)								
5	Customer Deposits	\$ (2,480,873)					\$ (2,480,873)					
6	Accumulated Deferred Income Taxes	\$ (9,246,678)		\$ 3,885,347				\$ (13,132,025)				
7	Total Deductions	\$ (23,012,323)	\$ -	\$ (7,399,425)	\$ -	\$ -	\$ (2,480,873)	\$ (13,132,025)	\$ -	\$ -	\$ -	
8	Allowance for Working Capital	\$ 53,791			\$ 53,791							
9	Total Rate Base	\$ (24,594,190)	\$ (1,092,448)	\$ (7,399,425)	\$ 53,791	\$ (2,480,873)	\$ (13,132,025)	\$ (543,210)	\$ -			

Southwest Gas Corporation
Summary of Rate Base Adjustments
Reconstruction Cost New Depreciated
Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule B.1 (RCND)
Page 1 of 1

Line No.	Description	Staff Adjustments	Yuma Manors Pipe Replacement B-1	Customer Advances for Construction B-2	Cash Working Capital B-3	Customer Deposits B-4	Accumulated Deferred Income Taxes - Acct. 190 B-5	Intangible Plant Added After the Test Year B-6	Accumulated Deferred Income Taxes - RCND B-7
1	Gross Utility Plant in Service	\$ (1,772,667)	\$ (1,229,457)					\$ (543,210)	
2	Less: Accumulated Depreciation	\$ 137,009	\$ 137,009						
3	Net Utility Plant in Service	\$ (1,635,658)	\$ (1,092,448)	\$ -	\$ -	\$ -	\$ -	\$ (543,210)	\$ -
4	Customer Advances for Construction	\$ (11,284,772)		\$ (11,284,772)					
5	Customer Deposits	\$ (2,480,873)				\$ (2,480,873)			
6	Accumulated Deferred Income Taxes	\$ (111,633,530)		\$ 3,885,347			\$ (20,109,648)		\$ (95,409,229)
7	Total Deductions	\$ (125,399,175)	\$ -	\$ (7,399,425)	\$ -	\$ (2,480,873)	\$ (20,109,648)	\$ -	\$ (95,409,229)
8	Allowance for Working Capital	\$ 53,791			\$ 53,791				
9	Total Rate Base	\$ (126,981,042)	\$ (1,092,448)	\$ (7,399,425)	\$ 53,791	\$ (2,480,873)	\$ (20,109,648)	\$ (543,210)	\$ (95,409,229)

Southwest Gas Corporation
Adjusted Net Operating Income

Docket No. G-01551A-07-0504
Schedule C
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
Operating Revenues				
1	Revenues	\$ 399,234,678	\$ -	\$ 399,234,678
2	Total Operating Revenues	<u>\$ 399,234,678</u>	<u>\$ -</u>	<u>\$ 399,234,678</u>
Operating Expenses				
3	Purchased Gas	\$ -	\$ -	\$ -
4	Other O&M Expenses	\$ 187,034,455	\$ (6,862,088)	\$ 180,172,367
5	Interest on Customer Deposits	\$ 1,915,314	\$ 148,852	\$ 2,064,166
6	Depreciation & Amortization	\$ 87,887,713	\$ (305,139)	\$ 87,582,574
7	Taxes Other Than Income Taxes	\$ 33,124,880	\$ 121,632	\$ 33,246,512
8	Income Taxes	\$ 16,092,218	\$ 2,816,391	\$ 18,908,609
9	Total Operating Expenses	<u>\$ 326,054,580</u>	<u>\$ (4,080,352)</u>	<u>\$ 321,974,228</u>
10	Net Operating Income	<u>\$ 73,180,098</u>	<u>\$ 4,080,352</u>	<u>\$ 77,260,450</u>

Notes and Source

Col. A: SWG filing, Schedule C-1

Col. B: Staff Schedule C.1

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Docket No. G-04204A-06-0463
Schedule C.1
Page 1 of 3

Test Year Ended April 30, 2007

Line No.	Description	Staff Adjustments	Yuma Manors Depreciation and Property Tax Expense	Gain on Sale of Utility Property	Management Incentive Program	Stock Based Compensation	Supplemental Executive Retirement Expense
			C-1	C-2	C-3	C-4	C-5
Operating Revenues							
1	Gas Retail Revenues	\$ -					
2	Other Operating Revenues	\$ -					
3	Total Operating Revenues	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Operating Expenses							
4	Purchased Gas	\$ -					
5	Other O&M Expenses	\$ (6,862,088)			\$ (2,019,268)	\$ (820,915)	\$ (1,625,460)
6	Interest on Customer Deposits	\$ 148,852					
7	Depreciation & Amortization	\$ (305,139)	\$ (54,370)	\$ (69,700)			
8	Taxes Other Than Income Taxes	\$ 121,632	\$ (28,945)		\$ 150,577		
9	PRE-TAX OPERATING EXPENSES	\$ (6,896,743)	\$ (83,315)	\$ (69,700)	\$ (1,868,691)	\$ (820,915)	\$ (1,625,460)
10	PRE-TAX OPERATING INCOME	\$ 6,896,743	\$ 83,315	\$ 69,700	\$ 1,868,691	\$ 820,915	\$ 1,625,460
11	Income Taxes	\$ 2,816,391	\$ 32,934	\$ 27,552	\$ 738,679	\$ 324,501	\$ 642,531
12	TOTAL OPERATING EXPENSES	\$ (4,080,352)	\$ (50,381)	\$ (42,148)	\$ (1,130,012)	\$ (496,414)	\$ (982,929)
13	OPERATING INCOME	\$ 4,080,352	\$ 50,381	\$ 42,148	\$ 1,130,012	\$ 496,414	\$ 982,929

Notes and Source

Combined Effective Tax Rate 39.5292%
Per SWG Schedule C-3, page 2

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Docket No. G-04204A-06-0463
Schedule C.1
Page 2 of 3

Test Year Ended April 30, 2007

Line No.	Description	American Gas Association Dues C-6	TRIMP Surcharge C-7	A&G Expenses - Annualized Paiute Allocation C-8	Interest on Customer Deposits C-9	Interest Synchronization C-10	Flow Back Excess Deferred Income Taxes C-11
Operating Revenues							
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Operating Expenses							
4	Purchased Gas						
5	Other O&M Expenses	\$ (80,138)	\$ (920,914)	\$ (23,447)	\$ 148,852		
6	Interest on Customer Deposits						
7	Depreciation & Amortization						
8	Taxes Other Than Income Taxes						
9	PRE-TAX OPERATING EXPENSES	\$ (80,138)	\$ (920,914)	\$ (23,447)	\$ 148,852	\$ -	\$ -
10	PRE-TAX OPERATING INCOME	\$ 80,138	\$ 920,914	\$ 23,447	\$ (148,852)	\$ -	\$ -
11	Income Taxes	\$ 31,678	\$ 364,030	\$ 9,268	\$ (58,840)	\$ 237,509	\$ (147,345)
12	TOTAL OPERATING EXPENSES	\$ (48,460)	\$ (556,884)	\$ (14,179)	\$ 90,012	\$ 237,509	\$ (147,345)
13	OPERATING INCOME	\$ 48,460	\$ 556,884	\$ 14,179	\$ (90,012)	\$ (237,509)	\$ 147,345

Notes and Source

Combined Effective Tax Rate 39.5292%
Per SWG Schedule C-3, page 2

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Docket No. G-04204A-06-0463
Schedule C.1
Page 3 of 3

Test Year Ended April 30, 2007

Line No.	Description	Injuries and Damages C-12	Leased Aircraft Operating Costs C-13	El Paso Natural Gas Rate Case Expense C-14	New Intangible Plant Annualized Amortizations C-15
Operating Revenues					
1	Gas Retail Revenues				
2	Other Operating Revenues				
3	Total Operating Revenues	\$ -	\$ -	\$ -	\$ -
Operating Expenses					
4	Purchased Gas				
5	Other O&M Expenses	\$ (861,717)	\$ (32,814)	\$ (477,415)	
6	Interest on Customer Deposits				
7	Depreciation & Amortization				\$ (181,069)
8	Taxes Other Than Income Taxes				
9	PRE-TAX OPERATING EXPENSES	\$ (861,717)	\$ (32,814)	\$ (477,415)	\$ (181,069)
10	PRE-TAX OPERATING INCOME	\$ 861,717	\$ 32,814	\$ 477,415	\$ 181,069
11	Income Taxes	\$ 340,630	\$ 12,971	\$ 188,718	\$ 71,575
12	TOTAL OPERATING EXPENSES	\$ (521,087)	\$ (19,843)	\$ (288,697)	\$ (109,494)
13	OPERATING INCOME	\$ 521,087	\$ 19,843	\$ 288,697	\$ 109,494

Notes and Source

Combined Effective Tax Rate 39.5292%
Per SWG Schedule C-3, page 2

Test Year Ended April 30, 2007

Line No.	Capital Source	Capitalization		Cost Rate	Weighted Avg. Cost of Capital
		Amount	Percent		
		(A)	(B)	(C)	(D)
	SWG - Proposed				
1	Long-Term Debt		51.00%	7.96%	4.06%
2	Preferred Equity		4.00%	8.20%	0.33%
3	Common Stock Equity		45.00%	11.25%	5.06%
4	Total Capital		100.00%		9.45%
	Supporting				
	OCRB				
5	Long-Term Debt	\$ 557,358,002	52.08%	7.96%	4.15%
6	Preferred Equity	\$ 47,944,774	4.48%	6.40%	0.29%
7	Common Stock Equity	\$ 464,893,080	43.44%	10.250%	4.45%
8	Total Capital	\$1,070,195,856	100.00%		8.88%
9	Difference				-0.57%
10	Weighted Cost of Debt				4.43%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base - Option 1				
11	Long-Term Debt	\$ 557,358,002	40.00%	7.96%	3.18%
12	Preferred Equity	\$ 47,944,774	3.44%	8.20%	0.28%
13	Common Stock Equity	\$ 464,893,080	33.37%	10.000%	3.34%
14	Capital financing OCRB	\$1,070,195,856			
15	Appreciation above OCRB not recognized on utility's books	\$ 323,152,085	23.19%	0% [a]	0.00%
16	Total capital supporting FVRB	\$1,393,347,941	100.00%		6.80%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base - Option 2				
17	Long-Term Debt	\$ 557,358,002	40.00%	7.96%	3.18%
18	Preferred Equity	\$ 47,944,774	3.44%	8.20%	0.28%
19	Common Stock Equity	\$ 464,893,080	33.37%	10.00%	3.34%
20	Capital financing OCRB	\$1,070,195,856			
21	Appreciation above OCRB not recognized on utility's books	\$ 323,152,085	23.19%	1.25% [b]	0.29%
22	Total capital supporting FVRB	\$1,393,347,941	100.00%		7.09%

Notes and Source

Lines 11-15, Col.A:

23	Fair Value Rate Base	\$1,393,347,942	Schedule A
24	Original Cost Rate Base	\$1,070,195,857	Schedule A
25	Difference	\$ 323,152,085	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

- [a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books.
Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books.
The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

- [b] Per Staff witness David Parcell

Test Year Ended April 30, 2007

Line No.	Description	Account	Account 376 Mains Amount (A)	Account 380 Services Amount (B)	Total Amount (C)	Reference
I. Costs Recorded by Company Though End of Test Year						
A. For New Plant Replacing the Original Plant						
1	Costs incurred prior to and during the test year	101	\$ 737,377	\$ 494,385	\$ 1,231,762	Note A
2	Accumulated Depreciation	108	\$ (1,099)	\$ (1,206)	\$ (2,305)	Note A
3	Net Plant in Service - replacement plant		\$ 736,278	\$ 493,179	\$ 1,229,457	Note A L.1 - L.2
B. For the Original Cost of Plant Installed 1954-1958						
1. Plant in Service						
4	Gas Plant in Service	101	\$ 151,539	\$ 27,462	\$ 179,001	Note A
5	Gas Plant Retired	101	\$ (151,539)	\$ (27,462)	\$ (179,001)	Note A
6	Gas Plant in Service After Retirement	101	\$ -	\$ -	\$ -	Note A
2. Accumulated Depreciation						
7	Accumulated Depreciation recorded at April 2007	108	\$ (271,280)	\$ (57,198)	\$ (328,478)	Note A
8	Gas Plant Retired	108	\$ 151,539	\$ 27,462	\$ 179,001	Note A
9	Removal costs incurred prior to and during the test year	108	\$ 4,137	\$ 8,331	\$ 12,468	Note A
10	Impact on Accumulated Depreciation	108	\$ (115,604)	\$ (21,405)	\$ (137,009)	Note A
11	Impact on Net Plant		\$ 115,604	\$ 21,405	\$ 137,009	Note A L6 - L10
III. Staff Adjustment						
12	Remove impact on test year of replacement plant		\$ (736,278)	\$ (493,179)	\$ (1,229,457)	- Line 3
13	Remove impact on test year of original plant retired		\$ 115,604	\$ 21,405	\$ 137,009	- Line 11
14	Adjustment to Test Year Net Plant		\$ (620,674)	\$ (471,774)	\$ (1,092,448)	
15	Adjustment to Test Year Plant in Service		\$ (737,377)	\$ (494,385)	\$ (1,231,762)	- Line 1 less Line 6
16	Adjustment to Test Year Accumulated Depreciation		\$ 116,703	\$ 22,611	\$ 139,314	- Line 2 less Line 10
17	Adjustment to Test Year Net Plant		\$ (620,674)	\$ (471,774)	\$ (1,092,448)	

Notes and Source

- A Responses to ACC-STF-7-1 and STF-11-6
Also see the direct testimony of Staff engineer Corky Hanson

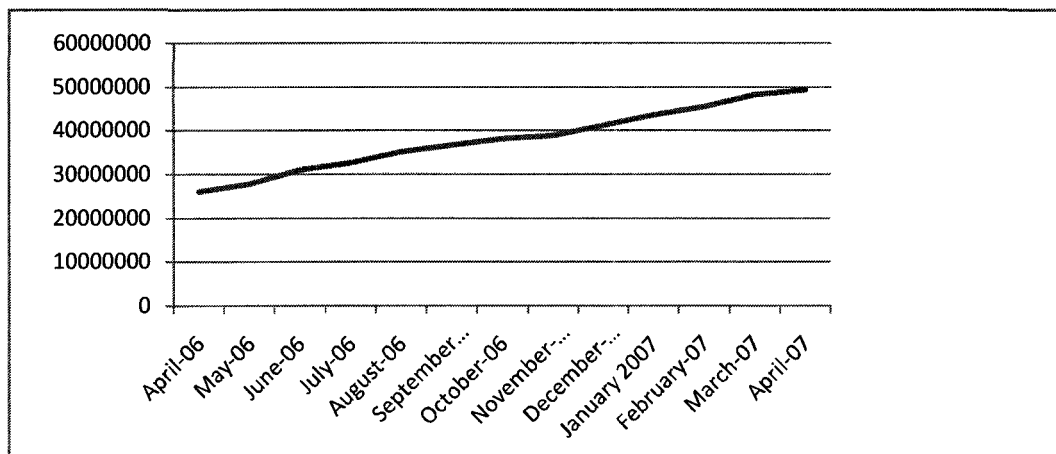
Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
		(A)	
1	Staff proposed	\$ (49,194,789)	See below
2	Company proposed	\$ (37,910,017)	See below
3	Staff adjustment to rate base	<u>\$ (11,284,772)</u>	Account 252
Related Accumulated Deferred Income Taxes:			
4	Related ADIT 34.43%	<u>\$ 3,885,347</u>	Response to STF 1.25, Customer Advances Account 2830 2100

Notes and Source

From Southwest Excel workpapers

	Month	Account 252 Amount	Monthly Change
		(B)	(C)
5	April-06	\$ 25,965,151.95	
6	May-06	\$ 27,771,678.00	\$ 1,806,526.05
7	June-06	\$ 30,949,083.64	\$ 3,177,405.64
8	July-06	\$ 32,596,096.25	\$ 1,647,012.61
9	August-06	\$ 35,041,274.23	\$ 2,445,177.98
10	September-06	\$ 36,572,842.62	\$ 1,531,568.39
11	October-06	\$ 38,058,790.21	\$ 1,485,947.59
12	November-06	\$ 38,732,669.00	\$ 673,878.79
13	December-06	\$ 41,078,965.78	\$ 2,346,296.78
14	January 2007	\$ 43,365,611.50	\$ 2,286,645.72
15	February-07	\$ 45,355,426.19	\$ 1,989,814.69
16	March-07	\$ 48,147,845.19	\$ 2,792,419.00
17	April-07	<u>\$ 49,194,789.04</u>	\$ 1,046,943.85
18	Average	\$ 37,910,017.20	
19	Year-End	<u>\$ 49,194,789.04</u>	
20	Adjustment	<u>\$ 11,284,771.84</u>	



Southwest Gas Corporation

Docket No. G-01551A-07-0504

Cash Working Capital

Schedule B-3

Test Year Ended April 30, 2007

Page 1 of 1

Line No.	Description	Per Company Cost (A)	Staff Adjustments (B)	Staff Adjusted (C)	Lag Days (D)	Dollar Days (E)
1	Cost of Gas	\$ 540,064,385	\$ -	\$ 540,064,385	42.30	\$ 22,842,405,297
2	Labor Cost	\$ 117,038,570	\$ (4,465,643)	\$ 112,572,927	12.33	\$ 1,388,567,236
3	Provision for Uncollected Accounts	\$ 2,977,729	\$ -	\$ 2,977,729	120.00	\$ 357,327,523
4	Other O & M Expenses	\$ 54,826,860	\$ (2,247,593)	\$ 52,579,268	8.40	\$ 441,803,544
5	Total O & M Expenses	\$ 714,907,545	\$ (6,713,236)	\$ 708,194,309	35.01	\$ 25,030,103,600
6	Interest	\$ 48,035,008	\$ (600,845)	\$ 47,434,163	84.65	\$ 4,015,438,873
7	Taxes Other Than Income Taxes	\$ 33,124,880	\$ 121,632	\$ 33,246,512	185.34	\$ 6,161,908,452
8	Income Taxes-Current	\$ 21,699,571	\$ 2,963,736	\$ 24,663,307	37.00	\$ 912,542,347
9	Total Operating Expenses Other Than Int	\$ 817,767,003	\$ 3,085,368	\$ 813,538,290	44.17	\$ 36,119,993,272
10	Number of Days in Test Period	365		365		
11	Average Daily Operating Expense	\$ 2,240,458		\$ 2,228,872		
12	Lag in Receipt of Revenue				39.53	
13	Net Difference Revenue-Expense Lag	(4.64)		(4.64)		
14	Cash Working Capital:					
15	Per Staff			\$ (10,348,550)		
16	Per Company	\$ (10,402,341)		\$ (10,402,341)		
17	Staff Adjustment (rounded to thousands)			\$ 53,791		
				\$ 54,000		

Notes and Source

Col.A: SWG Sch B-5, page 2 of 4

Col.B: Staff Schedule B-3 worksheet

Col.C: Col. A + Col.B

L.6: Schedule C-10, L.3, Synchronized interest

Col.D: SWG Sch B-5, page 2 of 4, except as noted

Col.E: Col. C x Col.D

Southwest Gas Corporation
Customer Deposits

Docket No. G-01551A-07-0504
Schedule B-4
Page 1 of 3

Test Year Ended April 30, 2007

Line No.	Description	Amount (A)	Reference
1	Staff proposed	\$ (34,402,771)	See below
2	Company proposed	\$ (31,921,898)	See below
3	Staff adjustment to rate base	<u>\$ (2,480,873)</u>	

Notes and Source

From Southwest Excel workpapers

	Month	Amount (B)	Monthly Change (C)
4	April-06	\$ 29,940,533.00	
5	May-06	\$ 30,244,307.00	\$ 303,774.00
6	June-06	\$ 30,534,168.00	\$ 289,861.00
7	July-06	\$ 30,907,667.00	\$ 373,499.00
8	August-06	\$ 31,068,422.00	\$ 160,755.00
9	September-06	\$ 31,294,649.00	\$ 226,227.00
10	October-06	\$ 31,925,334.07	\$ 630,685.07
11	November-06	\$ 32,387,659.54	\$ 462,325.47
12	December-06	\$ 32,677,847.19	\$ 290,187.65
13	January 2007	\$ 32,866,854.83	\$ 189,007.64
14	February-07	\$ 33,171,594.71	\$ 304,739.88
15	March-07	\$ 33,562,861.81	\$ 391,267.10
16	April-07	<u>\$ 34,402,770.85</u>	\$ 839,909.04
17	Average	\$ 31,921,897.62	
18	Year-End	<u>\$ 34,402,770.85</u>	
19	Adjustment	<u>\$ 2,480,873.23</u>	

Source: Company Records, Account 235
(excludes 235.0 1330)

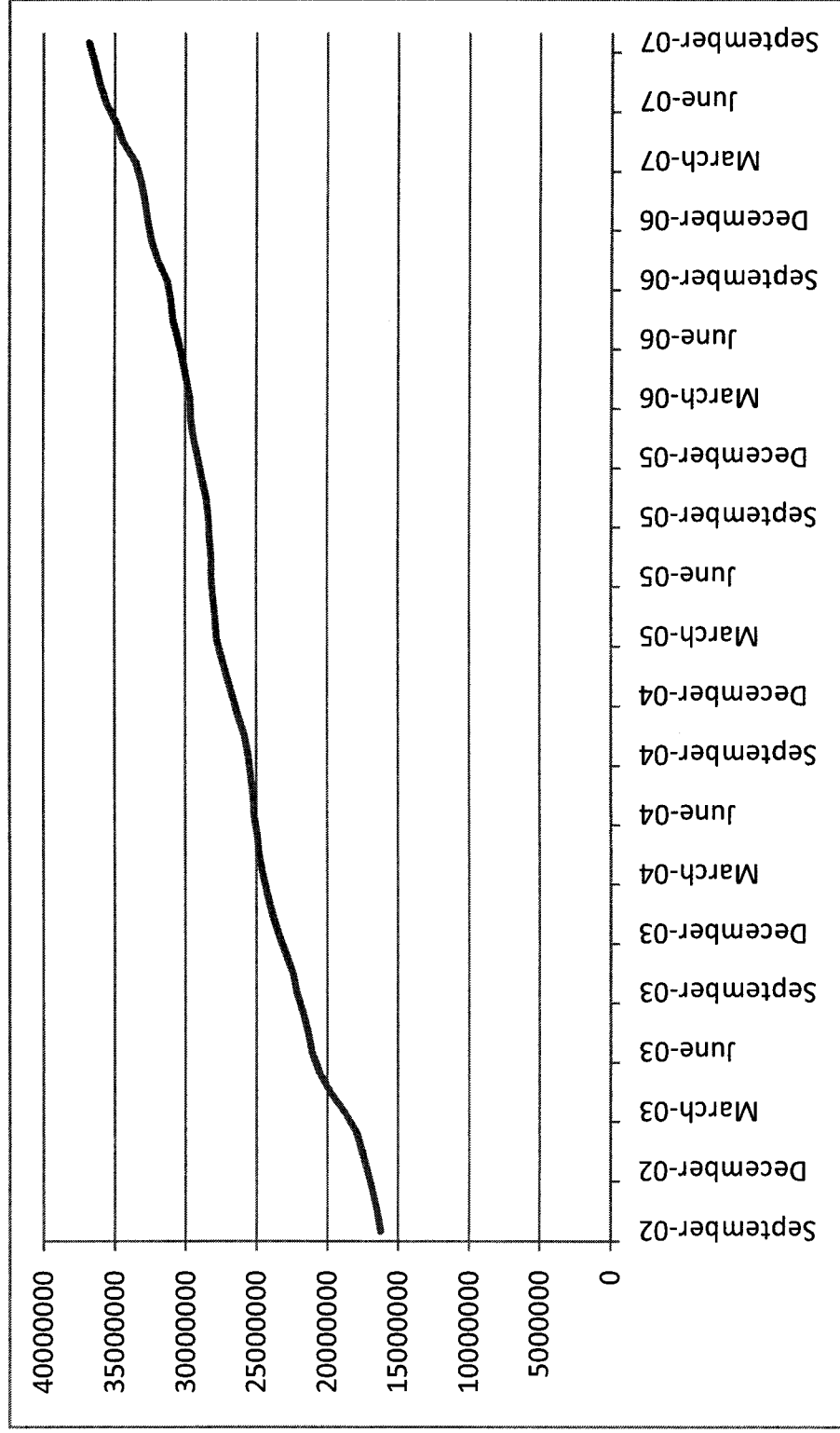
Test Year Ended April 30, 2007

Line No.	Month	Amount	Monthly Change
		(A)	(B)
1	September-02	\$ 16,250,822	
2	October-02	\$ 16,492,184	\$ 241,362
3	November-02	\$ 16,804,948	\$ 312,764
4	December-02	\$ 17,151,007	\$ 346,059
5	January-03	\$ 17,539,415	\$ 388,408
6	February-03	\$ 17,955,206	\$ 415,791
7	March-03	\$ 18,771,907	\$ 816,701
8	April-03	\$ 19,779,385	\$ 1,007,478
9	May-03	\$ 20,563,887	\$ 784,502
10	June-03	\$ 21,068,603	\$ 504,716
11	July-03	\$ 21,361,867	\$ 293,264
12	August-03	\$ 21,697,818	\$ 335,951
13	September-03	\$ 22,116,629	\$ 418,811
14	October-03	\$ 22,421,280	\$ 304,651
15	November-03	\$ 22,915,023	\$ 493,743
16	December-03	\$ 23,429,731	\$ 514,708
17	January-04	\$ 23,858,508	\$ 428,777
18	February-04	\$ 24,244,633	\$ 386,125
19	March-04	\$ 24,547,955	\$ 303,322
20	April-04	\$ 24,807,840	\$ 259,885
21	May-04	\$ 24,958,957	\$ 151,117
22	June-04	\$ 25,170,362	\$ 211,405
23	July-04	\$ 25,267,247	\$ 96,885
24	August-04	\$ 25,421,849	\$ 154,602
25	September-04	\$ 25,552,621	\$ 130,772
26	October-04	\$ 25,848,938	\$ 296,317
27	November-04	\$ 26,282,708	\$ 433,770
28	December-04	\$ 26,682,829	\$ 400,121
29	January-05	\$ 27,087,182	\$ 404,353
30	February-05	\$ 27,467,386	\$ 380,204
31	March-05	\$ 27,823,958	\$ 356,572
32	April-05	\$ 27,893,262	\$ 69,304
33	May-05	\$ 28,063,139	\$ 169,877
34	June-05	\$ 28,169,344	\$ 106,205
35	July-05	\$ 28,186,789	\$ 17,445
36	August-05	\$ 28,307,776	\$ 120,987
37	September-05	\$ 28,394,707	\$ 86,931
38	October-05	\$ 28,538,698	\$ 143,991
39	November-05	\$ 28,856,769	\$ 318,071
40	December-05	\$ 29,139,638	\$ 282,869
41	January-06	\$ 29,453,967	\$ 314,329
42	February-06	\$ 29,642,993	\$ 189,026
43	March-06	\$ 29,683,090	\$ 40,097
44	April-06	\$ 29,940,535	\$ 257,445
45	May-06	\$ 30,244,306	\$ 303,771
46	June-06	\$ 30,534,170	\$ 289,864
47	July-06	\$ 30,907,669	\$ 373,499
48	August-06	\$ 31,068,422	\$ 160,753
49	September-06	\$ 31,294,651	\$ 226,229
50	October-06	\$ 31,925,334	\$ 630,683
51	November-06	\$ 32,387,660	\$ 462,326
52	December-06	\$ 32,677,847	\$ 290,187
53	January-07	\$ 32,866,855	\$ 189,008
54	February-07	\$ 33,171,595	\$ 304,740
55	March-07	\$ 33,562,862	\$ 391,267
56	April-07	\$ 34,402,771	\$ 839,909
57	May-07	\$ 34,944,231	\$ 541,460
58	June-07	\$ 35,653,565	\$ 709,334
59	July-07	\$ 36,066,017	\$ 412,452
60	August-07	\$ 36,447,849	\$ 381,832
61	September-07	\$ 36,827,715	\$ 379,866

Source: Response to STF-1-9

All are positive, i.e., increases

Test Year Ended April 30, 2007



Southwest Gas Corporation
Accumulated Deferred Income Taxes

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Schedule B-5
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Test Year Ended April 30, 2007

Line No.	Description	Southwest Proposed Amount (A)	Staff Proposed Amount (B)	Staff Adjustment (C)	Reference
Original Cost Rate Base Adjustment					
1	Account 190\Deferred Tax Asset	\$ 20,877,149	\$ 7,745,124	\$ (13,132,025)	See below
Corresponding RCND Adjustment					
2	RCND Factor for Account 190 ADIT			1.531344	Page 2 of 2
3	Corresponding RCND Rate Base Adjustment			\$ (20,109,648)	L.1 x L.2

Notes and Source

Col.A: Company Schedule B-6, Sheet 3 of 3
Line 1, Account 190 ADIT Debit balance item:

	Per Southwest	Per Staff	Going-Forward Adjustment
4 Debit balance ADIT relating to Alternative Minimum Tax Carryforward	\$ 36,820,369	\$ 13,659,830	\$ (23,160,539)
5 Arizona Four-Factor Allocation	56.70%	56.70%	56.70%
6 Arizona Allocation	\$ 20,877,149	\$ 7,745,124	\$ (13,132,026)

A Per the Company's response to STF-11-10(a), the \$36.82 million represents the total Alternative Minimum Tax Credit (AMTC) for Southwest Gas Corporation as of 12/31/06. Sub-account 19002110 for \$25 million is the current portion of the AMTC that is expected to be utilized during the next 12 months, i.e., during the 2007 tax year. Sub-account 19002115 is the non-current portion of the AMTC and represents the amount that is expected to be utilized sometime after the 2007 tax year.

B AMT carryforward used in 2007 (per 3-15-08 estimate for 2007 corporate tax return extension filing)
This amount is therefore no longer being carried as an ADIT balance in Account 190 on a going-forward basis. Southwest currently expects to be able to apply an additional amount of its AMT carry-forward to reduce income tax in tax year 2009 (but not in tax year 2008); therefore, the remaining Account 190 balance is expected to remain during 2008 and beyond until utilized.

Source: Southwest Gas Tax Department, Lisa Moses

Southwest Gas Corporation
Account 190 Deferred Taxes by Vintage
At April 30, 2007

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Page 2 of 2

System Allocable				
Line No.	Year	Total Acct 190 Deferred Tax Asset at 4/30/07	4-Factor	Total Acct 190 Deferred Tax Asset at 4/30/07 for Arizona
1	1993	(33,127)	56.70%	(18,783)
2	1994	(1,180,873)	56.70%	(669,555)
3	1995	(2,033,739)	56.70%	(1,153,130)
4	1996	0	56.70%	0
5	1997	0	56.70%	0
6	1998	(7,175,288)	56.70%	(4,068,388)
7	1999	(18,722,588)	56.70%	(10,615,708)
8	2000	0	56.70%	0
9	2001	(6,360,549)	56.70%	(3,606,431)
10	2002	(647,026)	56.70%	(366,864)
11	2003	0	56.70%	0
12	2004	0	56.70%	0
13	2005	(667,179)	56.70%	(378,291)
14	2006	0	56.70%	0
15	2007	0	56.70%	0
16	Total	(36,820,369)		(20,877,149)

RCN Deferred Taxes for Acct 190			
H - W Index	Ratio to Current Index	Acct 190 RCN Deferred Taxes for Arizona	
291	1.76	(33,058)	
307	1.67	(1,118,157)	
309	1.66	(1,914,196)	
312	1.64	0	
320	1.60	0	
323	1.58	(6,428,053)	
332	1.54	(16,348,190)	
346	1.48	0	
352	1.45	(5,229,325)	
358	1.43	(524,615)	
373	1.37	0	
439	1.17	0	
517	0.99	(374,508)	
529	0.97	0	
512	1.00	0	
		(31,970,102)	

RCND value (31,970,102)
Original cost value (20,877,149)
RCND factor for Account 190 1.531344

17
18
19

Southwest Gas Corporation

Intangible Plant Added After the Test Year
That Was In Service by December 31, 2007
Test Year Ended April 30, 2007

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Page 1 of 1

Line No.	Description	Southwest Proposed Amount (A)	Staff Proposed Amount (B)	Staff Adjustment (C)	Reference
Original Cost Rate Base Adjustment					
1	New Intangible Plant	\$ 1,696,000	\$ 737,958	\$ (958,042)	See below
2	Arizona Four-Factor Allocation	56.70%	56.70%	56.70%	
3	Arizona Allocation	<u>\$ 961,632</u>	<u>\$ 418,422</u>	<u>\$ (543,210)</u>	

Notes and Source

Col.A: Company Proposed Per Southwest Gas Adjustment No. 14
Col.B: Staff Proposed per Company's Response to STF-11-4
Also see Schedule C-15, columns B and E

Line No.	Year	Arizona				System Allocable				RCN Deferred Taxes			
		Total Federal Tax Liability at 4/30/07	Total State Tax Liability at 4/30/07	Total Arizona Recorded Deferred Tax Liability at 4/30/07	Total Federal 282 Deferred Tax Liability at 4/30/07	Total Federal 190 Deferred Tax Asset at 4/30/07	Total Acct Tax Asset at 4/30/07	Total System Allocable at 4/30/07	4-Factor	Total Recorded Deferred Tax Liability at 4/30/07	Total AZ Deferred Tax Liability at 4/30/07	H - W Index	Ratio to Current Index
1	1953	1,859	291	2,150	0	0	0	0	56.70%	2,150	47	10.89	23,414
2	1954	(271)	(42)	(313)	0	0	0	0	56.70%	(313)	49	10.45	(3,271)
3	1955	162	25	187	0	0	0	0	56.70%	187	51	10.04	1,877
4	1956	(2,532)	(396)	(2,928)	0	0	0	0	56.70%	(2,928)	56	9.14	(26,762)
5	1957	(753)	(118)	(871)	0	0	0	0	56.70%	(871)	59	8.68	(7,560)
6	1958	(2,308)	(361)	(2,669)	0	0	0	0	56.70%	(2,669)	61	8.39	(22,993)
7	1959	381	2,432	2,813	0	0	0	0	56.70%	2,813	63	8.13	22,870
8	1960	(7,620)	(1,193)	(8,813)	0	0	0	0	56.70%	(8,813)	65	7.88	(69,446)
9	1961	10,750	1,683	12,433	(5)	(5)	(5)	(5)	56.70%	12,430	66	7.76	96,458
10	1962	(12,403)	(1,942)	(14,345)	0	0	0	0	56.70%	(14,345)	67	7.64	(109,596)
11	1963	(25,672)	(4,020)	(29,692)	19	19	19	19	56.70%	(29,681)	68	7.53	(223,500)
12	1964	(47,772)	(7,480)	(55,252)	0	0	0	0	56.70%	(55,252)	69	7.42	(409,970)
13	1965	(33,707)	(5,278)	(38,985)	(49)	(49)	(49)	(49)	56.70%	(39,013)	71	7.21	(281,282)
14	1966	(17,230)	(2,698)	(19,928)	0	0	0	0	56.70%	(19,928)	72	7.11	(141,688)
15	1967	5,885	921	6,806	(40)	(40)	(40)	(40)	56.70%	6,783	74	6.92	46,941
16	1968	(36,933)	(5,783)	(42,716)	(5)	(5)	(5)	(5)	56.70%	(42,719)	76	6.74	(287,925)
17	1969	(11,023)	(1,726)	(12,749)	0	0	0	0	56.70%	(12,749)	79	6.48	(82,614)
18	1970	(11,601)	(1,816)	(13,417)	0	0	0	0	56.70%	(13,417)	84	6.10	(81,844)
19	1971	3,506	549	4,055	48	48	48	48	56.70%	4,082	90	5.69	23,228
20	1972	(2,118)	(332)	(2,450)	93	93	93	93	56.70%	(2,397)	95	5.39	(12,921)
21	1973	21,291	3,334	24,625	(81)	(81)	(81)	(81)	56.70%	24,579	100	5.12	125,845
22	1974	81,690	12,791	94,481	0	0	0	0	56.70%	94,481	115	4.45	420,440
23	1975	1,228	192	1,420	108	108	108	108	56.70%	1,481	133	3.85	5,703
24	1976	60,416	9,460	69,876	(9)	(9)	(9)	(9)	56.70%	69,871	143	3.58	250,138
25	1977	23,368	3,659	27,027	(11,351)	(11,351)	(11,351)	(11,351)	56.70%	20,591	155	3.30	67,950
26	1978	46,293	7,248	53,541	326	326	326	326	56.70%	53,726	169	3.03	162,789
27	1979	1,333,385	208,774	1,542,159	0	0	0	0	56.70%	1,542,159	184	2.78	4,287,202
28	1980	1,012,547	158,539	1,171,086	(1,756)	(1,756)	(1,756)	(1,756)	56.70%	1,170,090	198	2.59	3,030,534
29	1981	478,969	74,994	553,963	38	38	38	38	56.70%	553,985	223	2.30	1,274,164
30	1982	193,572	30,308	223,880	1,449	1,449	1,449	1,449	56.70%	224,702	235	2.18	489,849
31	1983	632,984	99,109	732,093	3,709	3,709	3,709	3,709	56.70%	734,196	241	2.12	1,556,496
32	1984	7,838,504	1,227,307	9,065,811	335	335	335	335	56.70%	9,066,001	246	2.08	18,857,282
33	1985	3,351,835	524,810	3,876,645	18,321	18,321	18,321	18,321	56.70%	3,887,033	241	2.12	8,240,510
34	1986	6,108,046	956,362	7,064,408	(10,952)	(10,952)	(10,952)	(10,952)	56.70%	7,058,198	234	2.19	15,457,454
35	1987	4,331,907	678,264	5,010,171	(1,716)	(1,716)	(1,716)	(1,716)	56.70%	5,009,198	242	2.12	10,619,500
36	1988	5,289,269	828,162	6,117,431	(44,225)	(44,225)	(44,225)	(44,225)	56.70%	6,092,355	255	2.01	12,245,634
37	1989	3,939,340	616,799	4,556,139	781,665	781,665	781,665	781,665	56.70%	4,999,343	264	1.94	9,698,726
38	1990	4,708,170	737,177	5,445,347	32,590	32,590	32,590	32,590	56.70%	5,463,826	271	1.89	10,326,630
39	1991	2,001,984	313,459	2,315,443	89,422	89,422	89,422	89,422	56.70%	2,366,145	278	1.84	4,353,707
40	1992	2,352,840	368,394	2,721,234	24,138	24,138	24,138	24,138	56.70%	2,734,920	283	1.81	4,950,206
41	1993	2,821,601	441,790	3,263,391	21,122	(33,127)	(12,005)	(12,005)	56.70%	3,256,384	291	1.76	5,731,588
42	1994	2,998,550	469,495	3,468,045	(1,180,873)	(1,180,873)	(1,180,873)	(1,180,873)	56.70%	(624,997)	307	1.67	4,747,890
43	1995	3,825,639	598,996	4,424,635	191,218	(2,033,739)	(1,842,521)	(1,842,521)	56.70%	3,379,925	309	1.66	5,610,676
44	1996	4,082,540	639,220	4,721,760	82,646	82,646	82,646	82,646	56.70%	4,768,620	312	1.64	7,820,537
45	1997	3,903,337	611,161	4,514,498	123,485	0	123,485	123,485	56.70%	4,584,514	320	1.60	7,335,222
46	1998	6,753,167	1,057,371	7,810,538	346,634	(7,175,288)	(6,828,654)	(6,828,654)	56.70%	3,958,691	323	1.58	6,223,132
47	1999	8,728,276	1,366,622	10,094,898	504,506	(18,722,588)	(18,212,082)	(18,212,082)	56.70%	(234,755)	332	1.54	(361,522)
48	2000	7,310,098	1,144,572	8,454,670	344,295	0	344,295	344,295	56.70%	8,649,885	346	1.48	12,801,830
49	2001	7,028,031	951,099	7,979,130	796,497	(6,360,549)	(5,564,052)	(5,564,052)	56.70%	4,824,313	352	1.45	6,995,253
50	2002	16,104,379	1,448,826	17,553,205	1,313,889	(647,026)	666,863	666,863	56.70%	17,931,316	358	1.43	25,641,783
51	2003	17,138,584	1,195,708	18,334,292	8,082,682	0	8,082,682	8,082,682	56.70%	22,917,173	373	1.37	31,396,527
52	2004	23,408,345	1,045,414	24,453,759	1,018,923	0	1,018,923	1,018,923	56.70%	25,031,488	439	1.17	29,286,841
53	2005	1,844,435	288,791	2,133,226	1,705,754	(667,179)	1,038,575	1,038,575	56.70%	588,872	517	0.99	2,694,877
54	2006	(5,514,649)	(863,451)	(6,378,100)	1,081,147	0	1,081,147	1,081,147	56.70%	(5,765,090)	529	0.97	(5,592,137)
55	2007	(5,987,497)	(937,487)	(6,924,984)	(424,624)	0	(424,624)	(424,624)	56.70%	(7,165,746)	512	1.00	(7,165,746)
56	Total	138,065,125	16,287,934	154,353,059	16,148,831	(36,820,369)	(20,671,538)	(20,671,538)		142,632,297			238,041,526

Southwest Gas Corporation
Yuma Manors Depreciation and Property Tax Expense

Docket No. G-01551A-07-0504
Schedule C-1
Page 1 of 2

Test Year Ended April 30, 2007

Line No.	Description	Plant Amount (A)	Depreciation Rate (B)	Adjustment to Depreciation Expense (C)
1	Account 376, Mains	\$ (737,377)	3.82%	\$ (28,168)
2	Account 380, Services	\$ (494,385)	5.30%	\$ (26,202)
3	Adjustment to Annualized Depreciation Expense	<u>\$ (1,231,762)</u>		<u>\$ (54,370)</u>

Notes and Source

Col.A: Schedule B-1
Col.B: Response to ACC-STF-7-1
Col.C: Also see SWG's response to STF-11-6

FERC 403

Southwest Gas Corporation

Yuma Manors Depreciation and Property Tax Expense

Test Year Ended April 30, 2007

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Schedule C-1
Page 2 of 2

Line No.	Description	Amount	Reference
Adjustment to Property Tax Expense			
1	Adjustment to Net Plant in Service	\$ (1,092,448)	Note A
2	Statutory Assessment Ratio	23.0%	Note A
3	Taxable Value	\$ (251,263)	Note A
4	Property Tax Rate	11.52%	Notes A and B
5	Property Tax Expense Adjustment	<u>\$ (28,945)</u>	Note A

Notes and Source

- A Schedule B-1 and SWG's response to STF-11-6
B Also see Company's Schedule C-2, Adj. No. 15

FERC 408.1

Southwest Gas Corporation

Docket No. G-01551A-07-0504

Schedule C-2

Page 1 of 1

Gain on Sale of Property in Cave Creek, AZ

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Gain on Sale of Property in Cave Creek, AZ which had been included in gas plant in service	\$ 418,196	A
2	Ratepayer sharing percent	50.0%	A
3	Ratepayer sharing amount of gain	\$ 209,098	
	Normalization period, in years	3	B
4	Adjustment to pre-tax NOI for gain sharing	\$ (69,700)	

Notes and Source

- A SWG response to STF 1-96
- B Same period used by SWG for normalization of rate case cost, see SWG Sch C-2, Adj. No. 13

Southwest Gas Corporation
Management Incentive Program

Docket No. G-01551A-07-0504
Schedule C-3
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Adjustment to Management Incentive Program Expense	\$ (2,019,268)	A
2	Related Adjustment to Payroll Tax Expense	\$ 150,577	B

Notes and Source

A	Adjustment to Management Incentive Program Expense		
	Amount below from SWG's responses to STF-1-78 and RUCO-1-10		
3	Test Year amount of Management Incentive Program Expense (Corporate)	\$ 7,416,322	
4	Allocation to Paiute (MMF)	\$ (293,686)	3.96% C
5	Net of Allocation to Paiute	\$ 7,122,636	
6	Arizona Four Factor allocation rate per SWG Schedule C-1, sheet 17	56.70%	C
7	Test Year amount of Management Incentive Program Expense (Arizona)	\$ 4,038,535	
8	Shareholder allocation percentage	50%	
9	50% Allocation of MIP Expense to Shareholders	\$ 2,019,268	FERC 920
B	Adjustment to Payroll Tax Expense		
10	Adjustment to Test Year MIP Expense	\$ 2,019,268	D
11	Payroll Tax Expense Rate	7.457%	E
12	Adjustment to Payroll Tax Expense	\$ 150,577	

C SWG's response to STF-11-15 states that Southwest's annualized labor (shown in WP Sch C-2, Adj. No. 3) does not include MIP compensation or stock based compensation. Therefore, the cost of service filed by SWG does not include annualized payroll taxes related to these two items of compensation.

This adjustment, therefore, provides for annualized payroll tax expense on the portion of MIP allowed in rates.

D SWG's response to STF-9-10

E Estimated based on SWG's annualized payroll tax expense; is a Staff DR in Set 11 to ID specific info

Southwest Gas Corporation
Stock Based Compensation (Other Than MIP)

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Schedule C-4
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Adjustment to remove expense for Stock Based Compensation (other than MIP)	\$ (820,915)	A

Notes and Source

A	Test Year amount of Stock Based Compensation (Other than MIP)	\$ 1,507,520	STF-10-12
2	Test Year amount of Stock Based Compensation (Other than MIP)	\$ (59,698)	3.96% B
3	Allocation to Paiute (FERC via MMF)	\$ 1,447,822	
4	Net of Allocation to Paiute	56.70%	B
5	Arizona Four Factor allocation rate per SWG Schedule C-1, sheet 17	\$ 820,915	
6	Test Year amount of Stock Based Compensation (Other than MIP) - Arizona		

B SWG's response to STF-9-10
SWG's supplemental response to STF-6-41 that was referenced in SWG's response to STF-10-12(c)

Southwest Gas Corporation
Supplemental Executive Retirement Expense

Docket No. G-01551A-07-0504
Schedule C-5
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Test Year Supplemental Executive Retirement Expense (Arizona)	\$ (1,117,881)	A
2	Test Year Supplemental Executive Retirement Expense (Corporate Direct Arizona)	\$ (54,102)	A
3	System Allocable Amount of SERP (Arizona)	\$ (453,477)	A
4	Adjustment to Remove Supplemental Executive Retirement Expense	<u>\$ (1,625,460)</u>	B

Notes and Source

- A SWG Filing, WP Schedule C-2, page 8, line 11 as referenced by SWG's responses to STF-1-49 and RUCO 1.20 and STF-9-8
B Amount confirmed in SWG's response to STF-10-6

SERP is recorded by SWG in FERC 926 and then allocated to other expense accounts via SWG's labor loading.

Southwest Gas Corporation
American Gas Association Dues

Docket No. G-01551A-07-0504
Schedule C-6
Page 1 of 2

Test Year Ended April 30, 2007

Line No.	Description	Staff Adjustment (A)	Company Adjustment (B)	Net Staff Adjustment (C)	Reference
1	2007 AGA Dues per Filing	\$ 401,975	\$ 401,975		A
2	Recommended disallowance percentage	40%	3.39%		B
3	Recommended disallowance	\$ (160,790)	\$ (13,627)		L1 x L2
4	Less: Paiute & SGTC Allocation at 3.96%	\$ 6,367	\$ 540		C
5	Adjustment to AGA Dues Before Four-Factor	\$ (154,423)	\$ (13,087)		
6	Arizona Four-Factor Allocation	56.70%	56.70%		D
7	Adjustment to Arizona Related AGA Dues	\$ (87,558)	\$ (7,420)	\$ (80,138)	

Notes and Source

- A: SWG Filing, Schedule C-2, Adjustment No. 9, line 1
B: See testimony of Staff witness Ralph C. Smith and page 2 of this schedule
C: SWG Filing, Schedule C-1, sheet 18, which indicates a Modified Massachusetts Formula of 3.92% for Paiute and .04% for SGTC
D: SWG Filing, Schedule C-1, sheet 17

FERC Account 930.2

Southwest Gas Corporation
American Gas Association
Schedule of Expenses by NARUC Category

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Schedule C-6
Page 2 of 2

Line No.	NARUC Operating Expense Category	March 2005 NARUC Audit Report for Year Ended 12/31/02		AGA 2007 Budget			AGA 2008 Budget		
		% of Dues	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Public Affairs	24.13%	24.13%	23.29%	28.67%	28.67%	24.44%	30.63%	30.63%
2	Advertising			1.39%	1.71%	1.71%	1.18%	1.48%	1.48%
3	Communications	15.53%							
4	Corporate Affairs and International	10.54%	10.54%	8.44%	10.39%	10.39%	9.14%	11.46%	11.46%
5	General Counsel & Corp Secretary	5.20%	2.60%	4.09%	5.04%	2.52%	4.17%	5.23%	2.62%
6	Regulatory Affairs	15.51%							
7	Policy Planning & Regulatory Affairs			14.76%	18.17%		15.78%	19.78%	
8	Marketing Department	2.37%	2.37%						
9	Operating & Engineering Services	15.85%		24.11%	29.68%		21.71%	27.21%	
10	Policy & Analysis	12.94%							
11	Industry Finance & Admin. Programs	4.75%		5.16%	6.35%		3.36%	4.21%	
12	General & Administrative			18.77%			20.22%		
13	Total Expenses	106.82%	39.64%	100.01%	100.01%	43.29%	100.00%	100.00%	46.19%
14	Lobbying per IRC Section 162			2%			4%		

Notes and Source

Col.A: March 2005 Annual Audit Report on the Expenditures of the American Gas Association for the 12 month period ended December 31, 2002

Col.C: Southwest's Response to Staff data request STF-6-52

Col.F: Southwest's Response to Staff data request STF-6-50(b)

Southwest Gas Corporation
TRIMP Surcharges

Docket No. G-01551A-07-0504
Schedule C-7
Page 1 of 3

Test Year Ended April 30, 2007

Line No.	Description	Account	Test Year Recorded Amount (A)	Company Adjustment (B)	Company Adjusted (C)	Reference
1	TRIMP Related Regulatory Amortization	407.3	\$ 551,530	\$ (551,530)	\$ -	A
2	TRIMP Costs Written Off	887	\$ 348,690	\$ (348,690)	\$ -	A
3	Test Year TRIMP Costs	887		\$ 920,914	\$ 920,914	A
4	Adjustment to O&M Expense		\$ 348,690	\$ 572,224	\$ 920,914	
5	Staff adjustment to remove SWG pro forma TRIMP expense				\$ (920,914)	- Line 4

Notes and Source

- A SWG Filing, Schedule C-2, Adjustment No. 9
SWG response to data request STF-10-2

Southwest Gas Corporation
Test Year Ending April 30, 2007
Comparison of TRIMP Expense Proposed by Company
With Annual Average for First Five Years of TRIMP

Docket No. G-01551A-07-0504
Schedule C-7
Page 2 of 3

Line No.	Month	Year	TRIMP Cost	Average
1	January	2004	\$ -	
2	February		\$ -	
3	March		\$ -	
4	April		\$ -	
5	May		\$ 471.82	
6	June		\$ 6,544.60	
7	July		\$ 5,129.14	
8	August		\$ 34,505.15	
9	September		\$ 26,727.58	
10	October		\$ 43,458.93	
11	November		\$ 47,645.50	
12	December		\$ 249,744.24	
13	January	2005	\$ 3,287.69	
14	February		\$ 10,172.00	
15	March		\$ 112,724.24	
16	April		\$ 74,840.59	
17	May		\$ 34,496.78	
18	June		\$ 153,864.86	
19	July		\$ 59,016.31	
20	August		\$ 37,807.80	
21	September		\$ 74,315.00	
22	October		\$ 57,342.53	
23	November		\$ 81,834.80	
24	December		\$ 116,930.64	
25	January	2006	\$ 3,399.49	
26	February		\$ 112,185.46	
27	March		\$ 89,027.76	
28	April		\$ 14,517.99	
29	May		\$ 78,760.70	
30	June		\$ 25,798.91	
31	July		\$ 11,716.63	
32	August		\$ 25,738.65	
33	September		\$ 61,415.65	
34	October		\$ 40,789.65	
35	November		\$ 53,181.82	
36	December		\$ 184,304.68	
37	January	2007	\$ 1,696.82	
38	February		\$ 89,940.27	
39	March		\$ 51,725.37	
40	April		\$ 295,844.74	
41	May		\$ 219,060.96	
42	June		\$ 563,459.42	
43	July		\$ 161,869.56	
44	August		\$ 382,430.01	
45	September		\$ 606,095.91	
46	October		\$ 211,299.88	
47	November		\$ 145,226.48	
48	December		\$ 17,512.58	
49	GRAND TOTAL		<u>\$ 4,677,859.59</u>	<u>\$ 935,571.92</u> Average for First Five Year TRIMP Period
ANNUAL TOTALS				
50		2003	\$ -	
51		2004	\$ 414,226.96	
52		2005	\$ 816,633.24	
53		2006	\$ 700,837.39	
54		2007	\$ 2,746,162.00	
55	GRAND TOTAL		<u>\$ 4,677,859.59</u>	<u>\$ 935,571.92</u> Average for First Five Year TRIMP Period
Compare:				
56	Test Year Ending 4/30/07		<u>\$ 920,913.89</u>	Normalized O&M Expense for TRIMP Proposed by Southwest Gas

Notes and Source
Response to STF-9-18 and STF-10-2

Southwest Gas Corporation
 Test Year Ending April 30, 2007
 Estimated Replacement TRIMP Surcharge

Docket No. G-01551A-07-0504
 Schedule C-7
 Page 3 of 3

Line No.	Description	Amount	Reference
1	Normalized TRIMP Costs per Year	\$ 921,000	STF-10-2
2	Test Year rate case volumes	743,110,918	STF-10-2(B)
3	Estimated Replacement TRIMP Surcharge, \$/therm	<u>\$ 0.00124</u>	Line 1 / Line 2

Test Year Ended April 30, 2007

Line No.	Description	FERC Account	12 Months Ended April 30, 2007			MMF Allocation Paiute (D)	Paiute Annualized Expenses (E)	Paiute's A&G Expenses (F) - (E)	Amount Allocated to Arizona (G)
			Net Recorded (A)	Charged to Paiute (B)	Gross Recorded (C) (A) + (B)				
1	Administrative and General Salaries	920	56,785,724	2,402,071	59,187,795	3.92%	2,322,351	79,720	45,201
2	Office Supplies	921	10,322,576	438,378	10,760,954	3.92%	422,228	16,150	9,157
3	Outside Services Employed	923	8,919,827	378,579	9,298,406	3.92%	364,842	13,738	7,789
4	Property Insurance	924	373,578	91,630	465,208	21.09%	98,118	(6,487)	(3,563)
5	Injuries and Damages	925	9,299,361	395,033	9,694,394	3.92%	380,379	14,654	8,309
6	Miscellaneous General Expenses	930.2	5,507,176	233,944	5,741,120	3.92%	225,264	8,680	4,922
7	Rents	931	4,453,278	190,026	4,643,304	3.92%	182,189	7,836	4,443
8	Maintenance of General Plant	935	1,833,689	77,859	1,911,548	3.92%	75,003	2,855	1,619
9	Total		97,495,209	4,207,520	101,702,729		4,070,374	137,146	77,877
10	Revised Paiute Allocation Annualization per STF-1-53								\$ 77,877
11	Paiute Allocation Annualization as Filed								\$ 101,324
12	Adjustment to Paiute Allocation Annualization								\$ (23,447)

Notes and Source

Amounts from SWG's filing, Schedule C-2, Adjustment No. 12 except for line 6, which was revised per SWG's response to STF-1-53

Col. G: All accounts except FERC 924 - Property Insurance are allocated using the 56.70% four-factor. FERC 924 uses 54.92% from WP Schedule C-2, sheet 17

Southwest Gas Corporation
Interest on Customer Deposits

Docket No. G-01551A-07-0504
Schedule C-9
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Staff Adjustment to Customer Deposits	\$ (2,480,873)	A
2	Interest rate on Customer Deposits	6.0%	B
3	Adjustment to increase interest expense	<u>\$ 148,852</u>	L2 - L1

Notes and Source

- A Schedule B-4
B Customer Deposit interest rate from SWG Adjustment No. 16

Southwest Gas Corporation
Interest Synchronization

Docket No. G-01551A-07-0504
Schedule C-10
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Adjusted rate base	\$ 1,070,195,857	Schedule B
2	Weighted cost of debt	4.43%	Schedule D
3	Synchronized interest deduction	\$ 47,434,163	Line 1 x Line 2
4	Synchronized interest deduction per Company	\$ 48,035,008	Note A
5	Difference (decreased) increased interest deduction	\$ (600,845)	Line 3 - Line 4
6	Combined federal and state income tax rates	39.529%	Schedule A-1
7	Increase (decrease) to income tax expense	\$ 237,509	

Notes and Source

- A SWG Excel file, "A Schedules.xls"
Arizona, Summary Of Results Of Operations
and SWG Supporting Schedule C-1.

Southwest Gas Corporation
Flow Back Excess Deferred Income Taxes

Docket No. G-01551A-07-0504
Schedule C-11
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Excess Deferred Income Taxes for SWG-Arizona	\$ (442,035)	A
2	Amortization period, in years	3.0	B
3	Adjustment to income tax expense	<u>\$ (147,345)</u>	L2 / L1

Notes and Source

- A Southwest Gas Tax Department workpaper
Amount is as of 12/31/07
- B Same period as used by SWG to normalize rate case expense

Test Year Ended April 30, 2007

Line No.	Description	Company Test Year As Recorded (A)	Company Requested As Filed (B)	Company Requested As Corrected (C)	Staff Proposed (D)	Staff Adjustment (E)
	Arizona Direct					Col.D - Col.B
1	Legal and Other Costs	\$ 467,269	\$ 467,269	\$ 467,269	\$ 467,269	\$ -
2	Reserve for Self Insurance	\$ (558,765)	\$ (558,765)	\$ (858,765)	\$ 820,000 c	\$ 1,378,765
3	Self-Insured Workmen's Comp	\$ 497,524	\$ 497,524	\$ 497,524	\$ 497,524	\$ -
4	Total Arizona Direct	\$ 406,028	\$ 406,028	\$ 106,028	\$ 1,784,793	\$ 1,378,765
	Common Before Allocation to Arizona					
5	Legal and Other Costs	\$ 179,014	\$ 179,014	\$ 179,014	\$ 179,014	\$ -
6	Reserve for Self Insurance	\$ 200,000	\$ 4,130,256	\$ 5,030,024	\$ 200,000 c	\$ (3,930,256)
7	Self-Insured Workmen's Comp	\$ 23,243	\$ 23,243	\$ 23,243	\$ 23,243	\$ -
8	Insurance	\$ 9,292,136	\$ 9,738,915	\$ 9,738,915	\$ 9,738,915	\$ -
9	Subtotal before Paiute Allocation		\$ 14,071,428	\$ 14,971,196	\$ 10,141,172	\$ (3,930,256)
10	Paiute Allocation 3.96%	\$ (395,033) a	\$ (380,379) a	\$ (592,859)	\$ (401,590)	\$ (21,211)
11	Subtotal after Paiute Allocation	\$ 9,299,360	\$ 13,691,049	\$ 14,378,337	\$ 9,739,582	\$ (3,951,467)
	Arizona Allocation of Common					
12	Legal and Other Costs 56.70%	\$ 101,501	\$ 101,501	\$ 101,501	\$ 101,501	\$ -
13	Reserve for Self Insurance 56.70%	\$ 113,400	\$ 2,341,855	\$ 2,852,024	\$ 113,400	\$ (2,228,455)
14	Self-Insured Workmen's Comp 56.70%	\$ 13,179	\$ 13,179	\$ 13,179	\$ 13,179	\$ -
15	Insurance 56.70%	\$ 5,268,641	\$ 5,521,965	\$ 5,521,965	\$ 5,521,965	\$ -
16	Paiute Allocation 56.70%	\$ (223,984)	\$ (215,675)	\$ (336,151)	\$ (227,702)	\$ (12,027)
17	Total Common Allocated to Arizona	\$ 5,272,737	\$ 7,762,825	\$ 8,152,518	\$ 5,522,343	\$ (2,240,482)
18	Total Arizona Direct and Allocated	\$ 5,678,765	\$ 8,168,853	\$ 8,258,546	\$ 7,307,136	\$ (861,717)
19	Company's proposed adjustments to Account 925 in its filing		\$ 2,490,088	\$ 2,579,781	\$ (861,717)	
			Col.B - Col.A	Col.C - Col.A		
	Components of Company's proposed adjustments to Account 925, I&J Expense:					
20	SWG Adjustment 7, Out of Period Expenses		\$ 253,324	\$ 253,324	\$ 253,324	
21	SWG Adjustment 10, Self Insured Retention Normalization		\$ 2,228,455 b	\$ 2,318,148 b	\$ 1,366,738	
22	SWG Adjustment 12, A&G Expenses, Annualized Paiute Allocation		\$ 8,309	\$ 8,309	\$ 8,309	
23	Total Company-proposed adjustments to Account 925 expense		\$ 2,490,088	\$ 2,579,781	\$ 1,628,371	
24	Percentage increase over test year recorded amount		44%	45%	29%	
25	Staff proposed adjustment to SWG as-filed pro forma expense for Account 925				\$ (861,717)	\$ (861,717)
					L.23, Col.D - Col.B	

Notes and Source

- A SWG response to Staff data request STF-9-14
B Derived from SWG filing, Schedule C-2, Company Adjustment Nos. 7, 10 and 12 and response to STF-9-14
C SWG response to Staff data request STF-9-14
D See page 2 of this schedule for Staff analysis of ten years of recorded expense for

a Paiute allocation used by SWG in its filing does not calculate exactly to 3.96%

b SWG Adjustment 10, Self Insured Retention Normalization

Component	SWG Recorded	SWG Filed	SWG Corrected	Staff Adjusted	Staff Adjustment
26 Arizona Direct	\$ (558,765)	\$ (558,765)	\$ (858,765)	\$ 820,000	\$ 1,378,765
27 Common Allocated to Arizona	\$ 113,400	\$ 2,341,855	\$ 2,852,024	\$ 113,400	\$ (2,228,455)
28 Subtotals	\$ (445,365)	\$ 1,783,090	\$ 1,993,259	\$ 933,400	\$ (849,690)
29 Net SWG Proposed Adjustment, before change in Paiute allocation		\$ 2,228,455	\$ 2,438,624	\$ 1,378,765	

L.27, Col.B - Col.A L.27, Col.C - Col.A

To Line 21

30	Paiute allocation	\$ (223,984) Line 16	\$ (344,460)	\$ (236,011)	\$ (12,027)
31	Change in Paiute allocation from test year recorded		\$ (120,476)	\$ (12,027)	
32	Company's proposed corrected adjustment, net of change in Paiute allocation		\$ 2,318,148		\$ (861,717) c
			To Line 21		
33	Staff adjustment to Southwest recorded, net of change in Paiute allocation		\$ 1,366,738		
c	See page 2 of this schedule for details of Staff recommended normalized amount for self-insured expense.		To Line 21		

Line No.	Description	Year	Total Expense Recorded		Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire		Staff Proposed	
			Arizona (A)	Common (B)	Arizona (C)	Common (D)	Arizona (E)	Common (F)
Reserve for Self-Insurance Expense								
1		1998	\$ 751,083	\$ 500,000	\$ 751,083	\$ 500,000		
2		1999	\$ 500,000	\$ (200,000)	\$ 500,000	\$ (200,000)		
3		2000	\$ 1,080,545	\$ -	\$ 1,080,545	\$ -		
4		2001	\$ 426,955	\$ 100,000	\$ 426,955	\$ 100,000		
5		2002	\$ 350,000	\$ 200,000	\$ 350,000	\$ 200,000		
6		2003	\$ 1,941,509	\$ (300,000)	\$ 1,941,509	\$ (300,000)		
7		2004	\$ 2,154,000	\$ 275,000	\$ 2,154,000	\$ 275,000		
8		2005	\$ 1,360,224	\$ 10,367,500 a	\$ 1,360,224	\$ -		
9		2006	\$ (975,540)	\$ 200,000	\$ (975,540)	\$ 200,000		
10		2007 YTD November	\$ 588,629	\$ (25,500)	\$ 588,629	\$ (25,500)		
11	Total		\$ 8,177,405	\$ 11,117,000	\$ 8,177,405	\$ 749,500		
12	Ten Year Average		\$ 817,741	\$ 1,111,700	\$ 817,741	\$ 74,950	\$ 820,000 b	\$ 200,000 c
13	Paute allocation	0.03%		\$ (44,023)		\$ (2,968)		\$ (7,920)
14	Common before AZ allocation			\$ 1,067,677		\$ 71,982		\$ 192,080
15	AZ allocation	56.7%		\$ 605,373		\$ 40,814		\$ 108,909
16	AZ allocated and direct		\$ 817,741	\$ 605,373	\$ 817,741	\$ 40,814	\$ 820,000	\$ 108,909
Adjustment to Southwest Proposed as Filed								
17	Page 1, Col.B, Lines 2 and 13, respectively		\$ (558,765)	\$ 2,341,855	\$ (558,765)	\$ 2,341,855	\$ (558,765)	\$ 2,341,855
18	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average	L.16 - L.17	\$ 1,376,506	\$ (1,736,482)	\$ 1,376,506	\$ (2,301,041)	\$ 1,378,765	\$ (2,232,946)
19	Net adjustment to Arizona expense		\$ (359,977)		\$ (924,536)		\$ (854,181)	
			L.18, Col.A&B		L.18, Col.C&D		L.18, Col.E&F	
Adjustment to Southwest Proposed as Corrected								
20	Page 1, Col.C, Lines 2 and 13, respectively		\$ (858,765)	\$ 2,852,024	\$ (858,765)	\$ 2,852,024	\$ (858,765)	\$ 2,852,024
21	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average	L.16 - L.20	\$ 1,676,506	\$ (2,246,651)	\$ 1,676,506	\$ (2,811,210)	\$ 1,678,765	\$ (2,743,115)
22	Net adjustment to Arizona expense		\$ (570,146)		\$ (1,134,705)		\$ (1,064,350)	
			L.21, Col.A&B		L.21, Col.C&D		L.21, Col.E&F	

Notes and Source

Ten-Year Average is from the Company's workpapers for Schedule C-2, Adjustment No. 10, Sheets 72 to 75 and response to data requests STF-6-60 and STF-9-14.

- ^a The 2005 common expense is abnormally high because of the impact of a May 2005 leaking gas line fire. The eventual settlement of that incident exceeded the Company's self-retention in effect at the time of the occurrence, per the response to data requests, such as STF-10-11(B) and (F)
- ^b Ten-Year Average, rounded upward to nearest \$10,000
- ^c 2006 accrual used as reasonably representative; note this amount exceeds the 10-year average, excluding the impact of the abnormal and extreme payout relating to the May 2005 leaking gas line fire.

Southwest Gas Corporation
Leased Aircraft Operating Costs

Docket No. G-01551A-07-0504
Schedule C-13
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Amount (A)	Reference
Leased Aircraft Expense Allocated to Arizona			
1	Normalized expense	\$ 272,533	See line 13, below
2	Test year expense	\$ 305,347	Note A
3	Adjustment to test year expense	<u>\$ (32,814)</u>	Line 2 - Line 1

Notes and Source

A Response to STF-10-26

Account	2004 (B)	2005 (C)	2006 (D)	2007 (E)	Average (F)
4 908				\$ 1,800	\$ 450
5 920	\$ 208,306	\$ 220,273	\$ 259,841	\$ 231,208	\$ 229,907
6 921	\$ 181,231	\$ 225,338	\$ 216,448	\$ 193,086	\$ 204,026
7 930.2	\$ 28,500	\$ 42,210	\$ 53,300	\$ 35,950	\$ 39,990
8 931	\$ 24,101	\$ 27,026	\$ 24,049	\$ 25,134	\$ 25,078
9 935	\$ 679	\$ 924	\$ 4,297		\$ 1,475
10 Totals	<u>\$ 442,817</u>	<u>\$ 515,771</u>	<u>\$ 557,935</u>	<u>\$ 485,378</u>	<u>\$ 500,476</u>
11 Allocation to Paiute Pipeline				3.96%	\$ (19,819)
12 Aircraft Expense Net of PP/SGTC					\$ 480,657
13 Arizona allocation factor and normalized leased aircraft expense				56.70%	<u>\$ 272,533</u>

Southwest Gas Company
El Paso Natural Gas Rate Case Expense

Docket No. G-01551A-07-0504
Schedule C-14
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Year	Arizona Direct (A)	System Allocable (B)	Net of Paiute/SGTC		Arizona 4 Factor (D)	Allocable to Arizona (E)	Total Arizona (F)
				Allocation of 3.96%	(C)			
1	2005	\$ 117,761	\$ 37,438	\$ 35,955		56.70%	\$ 20,387	(A) + (E) \$ 138,148
2	2006	\$ 800,809	\$ 47,363	\$ 45,487		56.70%	\$ 25,791	\$ 826,600
3	2007	\$ 167,675	\$ -	\$ -		56.70%	\$ -	\$ 167,675
4	Total	<u>\$ 1,086,245</u>	<u>\$ 84,801</u>	<u>\$ 81,443</u>			<u>\$ 46,178</u>	<u>\$ 1,132,423</u>
5	Total Arizona Amount of El Paso Natural Gas Rate Case Legal & Consulting Expense							
6	Normalized Over 3 years							
7	Normalized Amount of El Paso Natural Gas Rate Case Legal & Consulting Expense							
8	Test Year Amount of El Paso Natural Gas Rate Case Legal & Consulting Expense							
9	Staff Adjustment to El Paso Natural Gas Rate Case Legal & Consulting Expense							
								\$ 1,132,423
								\$ 377,474
								\$ 854,889
								<u>\$ (477,415)</u>

Notes and Source

Amounts from SWG's response to ACC-STF-10-1

FERC 923

Southwest Gas Corporation
Depreciation and Amortization Annualization
New Intangible Plant Annualized Amortizations
New Amortizations Beginning Before 12/31/07

Docket No. G-01551A-07-0504
Schedule C-15
Page 1 of 1

Line No.	Description	Company Proposed Per Southwest Gas Adjustment No. 14				Per Staff - Company's Response to STF-11-4				Staff Adjustments		
		Estimated In-Service Date (A)	Estimated Asset Amount (B)	Service Life (C)	Annual Amortization (D)	Asset Amount (E)	Actual In-Service Date (F)	Annual Amortization (H)	Plant (I)	Annual Amortization (J)		
1	Autocad Map 3D 2007	6/30/2007	\$ 180,000	3 years	\$ 60,000	\$ 128,129	6/29/2007	\$ 42,710	E - B \$ (51,871)	H - D \$ (17,290)		
2	Pi Data Access	6/30/2007	\$ 24,000	3 years	\$ 8,000	\$ 25,900	6/27/2007	\$ 8,633	\$ 1,900	\$ 633		
3	Receivables Software	6/30/2007	\$ 105,000	3 years	\$ 35,000	\$ 76,084	6/29/2007	\$ 25,361	\$ (28,916)	\$ (9,639)		
4	Load Balancer	6/30/2007	\$ 38,000	3 years	\$ 12,667	\$ 37,781	5/24/2007	\$ 12,594	\$ (219)	\$ (73)		
5	MacKinney VS/Cobol License	6/30/2007	\$ 10,500	3 years	\$ 3,500	\$ 10,149	5/24/2007	\$ 3,383	\$ (351)	\$ (117)		
6	Citrix Presentation License	6/30/2007	\$ 83,000	3 years	\$ 27,667	\$ 82,628	5/24/2007	\$ 27,543	\$ (372)	\$ (124)		
7	San Lefthand Network Expansion	6/30/2007	\$ 15,500	3 years	\$ 5,167	\$ 15,489	5/24/2007	\$ 5,163	\$ (11)	\$ (4)		
8	EMRS/LMR Software Module	12/31/2007	\$ 430,000	3 years	\$ 143,333	\$ -	N/A	\$ -	\$ (430,000)	\$ (143,333)		
9	EMRS Software	12/31/2007	\$ 350,000	3 years	\$ 116,667	\$ -	after 12/31/07	\$ -	\$ (350,000)	\$ (116,667)		
10	Oracle UPK Licenses	12/31/2007	\$ 250,000	3 years	\$ 83,333	\$ 189,398	12/17/2007	\$ 63,133	\$ (60,602)	\$ (20,200)		
11	Oracle PUI Licenses	12/31/2007	\$ 210,000	3 years	\$ 70,000	\$ 172,400	8/27/2007	\$ 57,467	\$ (37,600)	\$ (12,533)		
12	Total New Amortizations		\$ 1,696,000		\$ 565,333	\$ 737,958		\$ 245,987	\$ (958,042)	\$ (319,346)		
13	4-Factor [2]		\$ 56,700%		\$ 320,544	\$ 56,700%		\$ 56,700%	\$ 56,700%	\$ 56,700%		
14	Net Adjustment after 4-Factor		\$ 961,632		\$ -	\$ 418,422		\$ 139,475	\$ (543,210)	\$ (181,069)		

Notes and Source

SWG amounts: Southwest's W/P Schedule C-2, Sheet 89, Adjustment No. 14
Staff amounts: Company's response to STF-11-4
Line 8: Per SWG's response to STF-1-4, the EMRS/LMR Module is still in CWIP
Line 9: EMRS Software not in service by 12/31/07

\$ 195,120 1/28/2008

Attachment RCS-3

Excerpts from NARUC-sponsored Audits of the
Expenditures of the American Gas Association

**AUDIT REPORT ON THE EXPENDITURES
OF THE
AMERICAN GAS ASSOCIATION
(For the 12 month period ended December 31,1999)**

JUNE 2001



**COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT**

**National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005**

Telephone No. (202) 1898-2200

**AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31,1999**

EXPENSE CATEGORY	PERCENTAGE
Public Affairs	15.43%
Communications	11.64%
Media Communications:	
Commercial Equipment	4.47%
Environmental	0.74 %
Promotional	0.74%
Residential Equipment	2.96%
Corporate Affairs & International	11.30%
General Counsel & Corporate Secretary	4.02%
Regulatory Affairs	11.20%
Marketing Services	15.02%
Operating & Engineering Services	14.70%
Policy & Analysis	12.07%
Industry Finance & Admin. Programs	2.94 %
General & Administrative Expense	0.00%
TOTAL	107.23% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1999

Docket No. G-01551A-07-0504
Attachment RCS-3
Page 4 of 11

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (5)	Adjusted Net Expense	% of Dues
03	Public Affairs	4,147,682	3, 4	(1,690,669)	455,752	2,912,765	15.43%
03	Communications		4	1,698,695	498,479	2,197,174	11.64%
08	Media Communications						
	Commercial Equipment	759,932	1,2	61,868	21,400	843,200	4.47%
	Environmental	126,708	1,2	10,316	3,568	140,592	0.74%
	Promotional	126,708	1,2	10,316	3,568	140,592	0.74%
	Residential Equipment	503,934	1,2	41,027	14,191	559,152	2.96%
06. 16	Corporate Affairs and International	1,483,688	3	(5,217)	655,144	2,133,615	11.30%
05	General Counsel & Corp. Secretary	588,436	3		170,907	759,343	4.02%
09	Regulatory Affairs	1,492,676	3	194,393	427,268	2,114,337	11.20%
08	Marketing Services	4,654,503	1, 2	(2,302,920)	484,237	2,835,820	15.02%
14	Operating & Engineering Services	1,949,534			826,051	2,775,585	14.70%
07	Policy & Analysis	1,374,743	1	277,704	626,659	2,279,106	12.07%
12	Industry Finance & Admin. Programs	498,349			56,969	555,318	2.94%
01.10.11	General & Administrative Expense	4,247,002	3	(2,809)	(4,244,193)		0.00%
Grand Total		<u>21,953,895</u>		<u>\$ (1,707,296)</u>	<u>\$ -</u>	<u>\$ 20,246,599</u>	<u>107.23%</u>

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

- 1 Allocation of Group Vice President's salaries.
- 2 Media Communications portion of division expenses.
- 3 Expenses transferred to Government Relations.
- 4 Breakout of communications portion of division expenses
- 5 G&A allocated on basis of equivalent full-time employees during 1999.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1999

COST
CENTER

DESCRIPTION

- 03 Communications develops informational materials for member companies and consumers and coordinates all media activity.
- Public affairs provides members with information on legislative developments: prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
- 08 Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
- Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
- Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
- Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applications of specific equipment.
- Institutional - to enhance the image of the natural gas industry as a business entity.
- Power Generation Natural Gas Equipment - explains cost-savings, energy-savings and other benefits provided by specific equipment for generating power.
- Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
- Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
- 12 Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.

- 05 General Counsel & Corporate Secretaw provides legal counsel to the Association
- 06 Corporate Affairs provides opportun'ities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.
- 09 Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.
- 08 Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.
- 14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.
- 07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

- 01 Office of the President provides senior management guidance for all A.G.A. activities.
- 10 Human Resources develops and administers employee programs and provides general office and personnel services.
- 11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.
- * Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.
- * Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Donnell's copy

LF-111

Docket No. G-01551A-07-0504
Attachment RCS-3
Page 7 of 11

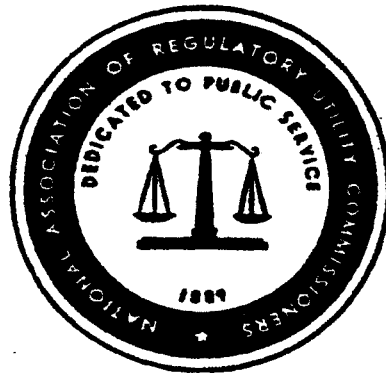
AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 1998)

JANUARY 2000



COMMITTEE ON UTILITY ASSOCIATION OVERSIGHT

**National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue, N.W., Suite 200
Washington, D.C. 20005**

Telephone No. (202) 898-2200

**AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 1998**

EXPENSE CATEGORY	PERCENTAGE
Communications	10.27%
MEDIA COMMUNICATIONS:	
Commercial Equipment	5.96%
Environmental	3.37%
Industrial Equipment	1.36%
Promotional	1.46%
Residential Equipment	8.40%
Finance & Administration Services	12.17%
General Counsel & Corporate Secretary	5.54%
Government Relations	23.86%
Marketing Services	16.20%
Meeting Services	-0.18%
Operating & Engineering Services	4.90%
Planning & Analysis	9.51%
General & Administrative Expense	0.00%
TOTAL	102.82% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1998

Docket No. G-01551A-07-0504
Attachment RCS-3
Page 9 of 11

<u>Group Number</u>	<u>Group Name</u>	<u>Net Expense</u>		<u>Adjustments</u>	<u>G&A Allocation (4)</u>	<u>Adjusted Net Expense</u>	<u>% of Dues</u>
03	Communications	1,561,612	2	(2,679)	430,782	1,989,715	10.27%
13	Media Communications						
	Commercial Equipment	1,105,739	1,2	31,943	17,848	1,155,530	5.96%
	Environmental	625,598	1,2	18,072	10,098	653,768	3.37%
	Industrial Equipment	252,954	1,2	7,307	4,083	264,344	1.36%
	Promotional	270,820	1,2	7,823	4,372	283,015	1.46%
	Residential Equipment	1,557,378	1,2	44,990	25,139	1,627,507	8.40%
06	Finance & Administration Services	1,797,937	3	(13,893)	574,377	2,358,420	12.17%
05	General Counsel & Corp. Secretary	938,797	3	(8,566)	143,594	1,073,825	5.54%
09	Government Relations	3,802,555	3	22,459	800,025	4,625,039	23.86%
08	Marketing Services	2,693,462	1	(107,456)	553,863	3,139,869	16.20%
04	Meeting Services	(34,155)		-	-	(34,155)	-0.18%
14	Operating & Engineering Services	661,825		-	287,188	949,013	4.90%
07	Policy & Analysis	1,392,718		-	451,296	1,844,014	9.51%
01,10,11	General & Administrative Expense	3,302,665		-	(3,302,665)	0	0.00%
Grand Total		<u>19,929,905</u>		<u>\$ 0</u>	<u>\$ 0</u>	<u>\$ 19,929,905</u>	<u>102.84%</u>

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

- 1 Allocation of Group Vice President's salaries.
- 2 Media Communications portion of division expenses.
- 3 Expenses transferred to Government Relations.
- 4 G&A allocated on basis of equivalent full-time employees during 1997.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1998

COST
CENTER

DESCRIPTION

- 03 Communications develops informational materials for member companies and consumers and coordinates all media activity.
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- Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
- Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
- Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applications of specific equipment.
- Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
- Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
- 06/ Finance & Administration develops and implements programs in such areas as
16 accounting, human resources and risk management for member companies.
- 05 General Counsel & Corporate Secretary provides legal counsel to the Association.
- 09 Government Relations provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.
- 08 Marketing assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

- 04 Meeting Services and Membership Services provides support services for committee meetings and conferences. In addition, coordinates services provided to members.
- 14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.
- 07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

- 01 Office of the President provides senior management guidance for all A.G.A. activities.
- 10 Human Resources develops and administers employee programs and provides general office and personnel services.
- 11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.
- * Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.
- * Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Excerpt from Florida PSC City Gas Company rate case 01152004

State of Florida

Public Service Commission

**Capital Circle Office Center 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850**

-M-E-M-O-R-A-N-D-U-M-

DATE:DECEMBER 23, 2003

**TO:DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE
SERVICES (BAYÓ)**

**FROM:DIVISION OF ECONOMIC REGULATION (BRINKLEY, BAXTER,
DRAPER, GARDNER, HEWITT, KAPROTH, KENNY, LESTER, LINGO, C. ROMIG,
SPRINGER, STALLCUP, WHEELER, WINTERS)
DIVISION OF COMPETITIVE SERVICES (MAKIN)
OFFICE OF THE GENERAL COUNSEL (JAEGER)**

**RE:DOCKET NO. 030569-GU - APPLICATION FOR RATE INCREASE BY CITY
GAS COMPANY OF FLORIDA.**

**AGENDA:01/06/04 - REGULAR AGENDA - PROPOSED AGENCY ACTION -
INTERESTED PERSONS MAY PARTICIPATE**

**CRITICAL DATES:5-MONTH EFFECTIVE DATE: JANUARY 15, 2004 (PAA
RATE CASE)**

SPECIAL INSTRUCTIONS:NONE

**FILE NAME AND LOCATION:S:\PSC\ECR\WP\City Gas 030569-GU\
Final.RCM
Final Attachments 1-5.123
Final Attachments 6A-7P.123
Final Attachment 8.xls**

ISSUE 39: Is City Gas's \$(2,847) adjustment to Account 921, Office Supplies and Expenses, for American Gas Association membership dues appropriate?

RECOMMENDATION: No. Account 921, Office Supplies and Expenses, should be reduced by an additional \$13,178 for American Gas Association membership dues related to charitable contributions and advertising that is not informational or educational in nature. (C. ROMIG)

STAFF ANALYSIS: On MFR Schedule G-2, Page 17 of 34, the Company included \$1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is \$39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to \$40,188. On MFR G-2, Page 2 of 34, it removed \$2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed \$4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of \$4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were \$39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on

inflation only at 2.0% for 2004. On that basis the 2004 amount is \$40,063 (\$39,277 x 1.02). Disallowing 40% would result in disallowing \$16,025 for 2004. The Company's \$2,847 adjustment reduces Staff's adjustment to \$13,178 (\$16,025 - \$2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional \$13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Attachment RCS-5
Copies of SWG's Responses to Data Requests
and Workpapers Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
STF-7-1	Yuma Manors System Improvement Project	No	2	2 - 3
STF-11-6	Yuma Manors System Improvement Project	No	3	4 - 6
STF-11-2	Cash Working Capital	No	1	7
STF-11-3	Cash Working Capital	No	2	8 - 9
STF-11-10(a)	ADIT	No	5	10 - 14
STF-1-96	Gain on Sale	No	3	15 - 17
STF-9-1	Gain on Sale	No	2	18 - 19
STF-11-15	Management Incentive Compensation	No	2	20 - 21
STF-1-49	Management Incentive Compensation & SERP	No	7	22 - 28
STF-1-87	Precedent	No	2	29 - 30
STF-10-12	Stock Based Compensation	No	2	31 - 32
SFAS 123R	SFAS No. 123 (Revised 2004) Share-Based Payment	No	17	33 - 49
STF-9-18	TRIMP	No	10	50 - 59
STF-1-53	Corrections	No	12	60 - 71
STF-10-1	El Paso	No	2	72 - 73
STF-1-25	Customer Advances	No	7	74 - 80
STF-1-9	Customer Deposits	No	7	81 - 87
STF-9-10	Management Incentive Compensation & Stock Based Compensation	No	3	88 - 90
STF-1-78	Management Incentive Compensation	No	9	91 - 99
RUCO-1-10	Management Incentive Compensation	No	2	100 - 101
STF-6-41	Stock Based Compensation	No	2	102 - 103
RUCO-1-20	SERP	No	1	104
STF-9-8	SERP	No	2	105 - 106
STF-10-6	SERP	No	5	107 - 111
STF-6-52	AGA Dues	No	2	112 - 113
STF-6-50(b)	AGA Dues	No	2	114 - 115
STF-10-2	TRIMP	No	12	116 - 127
STF-9-14	Injuries & Damages	No	11	128 - 138
STF-10-11	Injuries & Damages	No	3	139 - 141
STF-6-60	Injuries & Damages	No	4	142 - 145
STF-6-61	Injuries & Damages (Supplemental)	No	5	146 - 150
STF-10-26	Leased Aircraft	No	2	151 - 152
STF-11-4	Amortizations	No	3	153 - 155
	Total Pages Including this Page		155	

259-001

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-7
(ACC-STF-7-1 THROUGH ACC-STF-7-7)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: JANUARY 10, 2008

Request No. ACC-STF-7-1:

Please provide all costs associated with the replacement of the Yuma Manors System Improvement Project. The system boundaries are: west: Arizona Avenue; east: Engler Avenue; north: Morrison Avenue; and south: 26th place.

- (a) Please show such costs by account.
- (b) Please also show such costs, by account, segregated into each of the following time periods:
 - (1) costs incurred prior to the test year,
 - (2) costs incurred during the test year, and
 - (3) costs incurred after the end of the test year.

Respondent: Property Accounting

Response:

The following are the costs associated with the replacement of the Yuma Manors System Improvement Project.

FERC account 376

Installation costs incurred prior to test year	\$0
Installation costs incurred during the test year	\$737,377
Installation costs incurred after the test year	\$19,508
Removal costs incurred prior to test year	\$0
Removal costs incurred during the test year	\$4,137
Removal costs incurred after the test year	\$0
Original cost retired	\$151,539
Depreciation rate	3.82%

(Continued on Page 2)

259-001
Page 2

Response to ACC-STF-7-1: (continued)

FERC account 380

Installation costs incurred prior to test year	\$0
Installation costs incurred during the test year	\$494,385
Installation costs incurred after the test year	\$0
Removal costs incurred prior to test year	\$0
Removal costs incurred during the test year	\$8,331
Removal costs incurred after the test year	\$0
Original cost retired	\$27,462
Depreciation rate	5.30%

All of the retirements, both main and service, were 1950s vintage.

298-006

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 THROUGH ACC-STF-11-15)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 3, 2008

Request No. ACC-STF-11-6:

Yuma Manors pipe replacement. Refer to the response to ACC-STF-7-1. (a) Please confirm each of the following amounts accurately represent the costs recorded to Plant in Service and Accumulated Depreciation through the end of the test year for this project:

Line No.	Description	Account 376 Mains Amount (A)	Account 380 Services Amount (B)	Total Amount (C)
I. Costs Recorded by Company Through End of Test Year				
Costs Affecting Test Year Plant in Service (Cr.) Dr.				
1	Costs incurred prior to and during the test year	\$ 737,377	\$ 494,385	\$ 1,231,762
2	Original cost retired	\$ (151,539)	\$ (27,462)	\$ (179,001)
3	Impact on test year Plant in Service	\$ 585,838	\$ 466,923	\$ 1,052,761
Costs Affecting Accumulated Depreciation (Cr.) Dr.				
4	Removal costs incurred prior to and during the test year	\$ 4,137	\$ 8,331	\$ 12,468
5	Original cost retired	\$ 151,539	\$ 27,462	\$ 179,001
6	Impact on Accumulated Depreciation	\$ 155,676	\$ 35,793	\$ 191,469
7	Impact on Net Plant	\$ 741,514	\$ 502,716	\$ 1,244,230

If any of the above, is not accurate, please provide accurate information showing the amounts affecting end-of-test-year Plant in Service and Accumulated Depreciation related to this project.

(b) Please identify the monthly amounts of Depreciation Expense recorded by Southwest Gas during the test year on the Mains and Services related to the Yuma Manors System Improvement Project.

(c) Please identify the annualized Depreciation Expense that Southwest included in its filing related to the Mains and Services related to the Yuma Manors System Improvement Project. Include supporting calculations.

(Continued on Page 2)

298-006
Page 2

Response to ACC-STF-11-6: (continued)

(d) Please identify the pro forma Property Tax Expense that Southwest included in its filing related to the Mains and Services related to the Yuma Manors System Improvement Project. Include supporting calculations.

Respondent: Revenue Requirements

Response:

a) Attached is the original cost of the plant first placed into service from 1954 to 1958 and the accumulated depreciation recorded over the last 50 years. In addition, attached is the net plant included in rate base related to the capital expenditure required to replace the 50 year old plant.

b) For mains, \$1,099 of depreciation expense was recorded in April 2007. For services, \$31 was recorded in February 2007, \$377 was recorded in March 2007, and \$798 was recorded in April 2007.

c) & d) For the information requested in parts (c) and (d) above, please see the attached spreadsheet.

**SOUTHWEST GAS CORPORATION
ARIZONA
RESPONSE TO STAFF DATA REQUEST STF-11-6 (A), (C), AND (D)
ORIGINAL COST OF PLANT INSTALL BETWEEN 1954 AND 1957
AND THE COST TO REPLACE IN 2007**

Description	Account Number	Mains	Services	Total
<u>Original Cost Of Plant Installed 1954-1958</u>				
Gas Plant In-Service	101	\$ 151,539	\$ 27,462	\$ 179,001
Less: Gas Plant Retired		(151,539)	(27,462)	(179,001)
Gas Plant In-Service After Retirement	101	\$ 0	\$ 0	\$ 0
Accumulated Depreciation	108			
Recorded at April 2007		\$ 271,280	\$ 57,198	\$ 328,478
Less: Gas Plant Retired		(151,539)	(27,462)	(179,001)
Add: Removal Cost		(4,137)	(8,331)	(12,468)
Accumulated Depreciation After Retirement	108	\$ 115,604	\$ 21,405	\$ 137,009
Net Plant In Service at April 2007		\$ (115,604)	\$ (21,405)	\$ (137,009)
<u>Plant Replacing the 1954-1957 Original Plant</u>				
Gas Plant In-Service	101	\$ 737,377	\$ 494,385	\$ 1,231,762
Less: Accumulated Depreciation	108	1,099	1,206	2,305
Net		\$ 736,278	\$ 493,179	\$ 1,229,457
Net Plant In Rate Base		\$ 620,674	\$ 471,774	\$ 1,092,448
<u>Property Tax Calculation Item D</u>				
Net Plant				\$ 1,092,448
Assessment Ratio				0.23
Assessed Value				\$ 251,263
Assessment Rate				11.52%
Property Tax Calculation				\$ 28,946
<u>Depreciation Expense Item C</u>				
Mains		\$ 737,377	3.82%	\$ 28,168
Services		494,385	5.30%	26,202
Total		\$ 1,231,762		\$ 54,370

298-002

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * ***

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 THROUGH ACC-STF-11-15)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 3, 2008

Request No. ACC-STF-11-2:

Cash working capital - revenue based taxes. (a) Did Southwest Gas reflect the lag related to the payment of revenue-based taxes in its lead-lag study? If not, explain fully why not. If so, please show exactly where and how the lag for revenue based taxes is reflected. (b) For each type of revenue based taxes and assessments that Southwest collects from ratepayers, please identify when the payment becomes due. For each type of revenue based taxes and assessments that Southwest collects from ratepayers, please relate the payment date (1) to the date the bill is issued to the customer, and, separately, (2) to the date Southwest collects the billed revenue from the customer. (c) Please provide the supporting documents that specify when the each type of revenue based taxes and assessments that Southwest collects from ratepayers must be remitted by Southwest to the taxing or assessing authority.

Respondent: Revenue Requirements

Response:

Southwest Gas does not calculate the revenue-based taxes in its lead-lag study. Raw data related to revenue-based taxes was provided in response to STF-11-3.

Almost all of the revenue-based taxes are paid on a monthly basis and the payment date of these taxes is essentially the same date as the revenue is received making any lag time for taxes de minimus.

298-003

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 THROUGH ACC-STF-11-15)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 3, 2008

Request No. ACC-STF-11-3:

Cash working capital - revenue based taxes. (1) Please provide the following information for each period, (i) 2006, (ii) 2007 and (iii) the 12 months ending April 30, 2007: (a) state sales tax billed, (b) city sales tax billed, (c) county sales tax billed, (d) sales tax unbilled, (e) franchise taxes, (f) ACC assessment, (g) any other revenue-based taxes/assessments (identify, quantify and explain).

(2) Please provide the following information for each period, (i) 2006, (ii) 2007 and (iii) the 12 months ending April 30, 2007: (a) the revenues subject to state sales tax billed, (b) the revenues subject to city sales tax billed, (c) the revenues subject to county sales tax billed, (d) the revenues subject to sales tax unbilled, (e) the revenues subject to franchise taxes, (f) the revenues subject to ACC assessment, (g) the revenues subject to any other revenue-based taxes/assessments (identify, quantify and explain).

(3) Please provide the following information for each period, (i) 2006, (ii) 2007 and (iii) the 12 months ending April 30, 2007: (a) the payment lag related to state sales tax billed, (b) the payment lag related to city sales tax billed, (c) the payment lag related to county sales tax billed, (d) the payment lag related to sales tax unbilled, (e) the payment lag related to franchise taxes, (f) the payment lag related to ACC assessment, (g) the payment lag related to any other revenue-based taxes/assessments (identify, quantify and explain).

(4) Please identify, quantify and explain all Southwest pro forma adjustments to revenue for the test year ending April 30, 2007 that would impact the amount of revenue-based taxes and assessments. For each revenue adjustment, please identify, quantify and explain each type of revenue-based tax and assessment that would be impacted by the adjustment to such revenue.

Respondent: Revenue Requirements

(Continued on Page 2)

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Page 2

Response to ACC-STF-11-3: (continued)

Response:

(1) - (3) Southwest Gas has not performed any study related to revenue based taxes. Raw data has been supplied on CD's for the information requested.

(4) The proforma annualization and weather normalization volume and bill adjustments are shown in Workpapers Schedule H-2, Sheet 42. The resulting revenue adjustment of (\$597,154,892), including gas cost, is calculated on Schedule C-2, Adjustment 1, Sheet 1 of 1.

298-010

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

* * *

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 THROUGH ACC-STF-11-15)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 3, 2008

Request No. ACC-STF-11-10:

Accumulated Deferred Income Taxes. (a) Please identify, quantify and explain the two items that comprise the ADIT balance in Account 190 used to derive the rate base amount ($= -25000000 + -11820369$) totaling \$36,820,369 before application of the 4-factor allocator. (b) Please provide the information requested in STF-1-25 as of 12/31/05 and 12/31/06 including: For each item, identify the book/tax-timing difference that causes the ADIT, explain when that temporary timing difference first arose, identify the amount of the timing difference as of each date, and describe in detail whether and how that particular timing difference relates to an item of utility rate base, utility revenue and/or utility expense, and how the related item has been reflected in the Company's filing for ratemaking purposes. (c) For each item of ADIT as of 4/30/07, please provide a detailed itemization of the ADIT item. Also, for each item, please identify the book/tax-timing difference that causes the ADIT, explain when that temporary timing difference first arose, identify the amount of the timing difference as of each date, and describe in detail whether and how that particular timing difference relates to an item of utility rate base, utility revenue and/or utility expense, and how the related item has been reflected in the Company's filing for ratemaking purposes. (d) For each line item listed in the Deferred Taxes Column of the table below with a dollar amount other than zero, please state whether the item has been reflected in rate base by Southwest Gas, and if not, explain fully why not. (e) For each item in the Arizona column of the table below, by account, please state whether the item has been reflected in rate base by Southwest Gas, and if not, explain fully why not.

(Continued on Page 2)

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Response to ACC-STF-11-10: (continued)

Line No.	Account Description (a)	Account Number (b)	Deferred Taxes (f)	As Adjusted (g)	Arizona (h)
				(i)	
1	Other Special Funds - Cash Surrender Value	1280-1160	0 \$		0
	<u>Working Funds</u>				
2	Working Funds	1350-0001	0 \$	489,115 \$	277,328
3	Petty Cash	1350-1015	0	68,216	38,679
4	Employee Expense Advances	1350-1072	0	95,226	53,993
5	Total		0 \$	652,558 \$	370,000
	<u>Prepayments</u>				
12	Postage	1650-0001	(290,138) \$	443,847 \$	251,661
13	Insurance Other	1650-1129	0	4,162,456	2,360,112
14	Arizona License and Franchise Taxes	1650-1129	0	0	0
15	Office Supplies-General	1650-1130	0	6,196	3,513
16	Plane Lease-Cheyenne	1650-1145	0	25,336	14,365
17	Commercial Paper Facility	1650-1353	0	0	0
18	Total		(290,138) \$	4,637,834 \$	2,629,652
	<u>Miscellaneous Current Assets</u>				
19	Employee Homes	1740-1150	0 \$	676,550 \$	383,604
25	Total		0 \$	676,550 \$	383,604
	<u>Other Regulatory Assets</u>				
3	Trans. Integ. MGMT Program - Arizona	1823-1904	0	5,099	5,099
4	Deferred Service Investigation - Arizona	1823-1928	(332,379)	508,465	508,465
5	Arizona Rate Case 2005	1823-1931	(5,859)	8,962	8,962
6	Arizona Rate Case 2000	1823-1936	(19,574)	29,945	29,945
8	Incremental Life/Care Programs	1823-1943	0	372,961	372,961
9	Low Income Program Arizona	1823-1945	(602,620)	921,874	921,874
22	Total		(960,432) \$	1,847,305 \$	1,847,305
	<u>Injuries and Damages</u>				
5	Arizona	2282-0001	(693,923)	1,061,547	1,061,547
6	System Allocable	2282-0001	(278,225)	425,621	241,327
7	Total		(972,148) \$	1,487,168 \$	1,302,874
	<u>Miscellaneous Current & Accrued Liab</u>				
8	Miscellaneous Current & Accrued Liab	2420-0001	0 \$	(4,580) \$	(2,597)
9	Prepaid Pension Asset	2420-1140	(4,164,420)	15,344,927	8,700,573
14	Accrued Incentive Pay	2420-1371	0	3,007,876	1,705,466
16	Accrued PBOP Costs	2420-1380	(168,613)	321,678	182,391
17	Accrued Health & Dental	2420-1383	(1,305,021)	2,322,902	1,317,085
18	Accrued SERP	2420-1387	(7,245,743)	11,084,359	6,284,832
19	Accrued Lease Rental-Headquarters	2420-1392	0	391,026	221,712
21	Total		(12,883,796) \$	32,468,187 \$	18,409,462
	<u>Other Deferred Credits</u>				
2	Deferred Comp-Officers	2530-1151	(4,853,239)	7,424,366	4,209,616
3	Deferred Comp-Directors	2530-1152	(1,641,287)	2,510,801	1,423,624
4	Deferred Comp-Inactive Officers	2530-1155	(3,368,822)	5,153,542	2,922,058
5	Deferred Comp-Inactive Directors	2530-1156	(745,262)	1,140,083	646,427
11	CIAC Gross up-Arizona	2540-1472	7,803	27,542	27,542
13	Total		(10,600,808) \$	16,256,334 \$	9,229,267

Respondent: Tax/Revenue Requirements

Response: **SUPPLEMENTAL ATTACHMENT – MARCH 21, 2008**

(a) The balance in Account 190, of \$36,820,369, represents the total alternative minimum tax credit (AMTC) for Southwest Gas Corporation. A copy of Form

(Continued on Page 3)

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Page 3

Response to ACC-STF-11-10: (continued)

8827 (Credit for Prior Year Minimum Tax Corporations), filed with the 2006 tax return, is attached. Account 190 is divided into two sub-accounts. Sub-account 19002110 (\$25,000,000) is the current portion of the AMTC and represents the estimated amount of the AMTC that is expected to be utilized during the next twelve months. Sub-account 19002115 (\$11,820,369) is the non-current portion of the AMTC and represents the amount that is expected to be utilized sometime after the following twelve months.

The AMTC is the excess of alternative minimum tax over regular tax paid by the company in all prior years. The AMTC does not expire and is available to reduce the regular tax to the extent the regular tax exceeds alternative minimum tax in all future years, until the AMTC is fully utilized.

- (b) Please refer to the attached schedules for explanations and amounts.
- (c) Please refer to the attached schedule for explanations and amounts.
- (d) Please refer to the Company's response to STF-11-1 for the twelve month average balances ended April 2007. The debits and credits on the attachment to the Company's response to STF-11-1 to the extent there are deferred taxes they are not reflected in rate base in this proceeding, with one exception; Account 2540-2109 is included in the deferred taxes used as a rate deduction in the Company's application.
- (e) Please refer to the Company's response to STF-11-1.

Form **8827**
Department of the Treasury
Internal Revenue Service
Name

Credit for Prior Year Minimum Tax - Corporations

► Attach to the corporation's tax return.

2006

Employer identification number	
88-0085720	
1	667,179.
2	36,153,190.
3	
4	36,820,369.
5	29,720,077.
6	30,382,192.
7	
8	
9	36,820,369.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES

- Alternative minimum tax (AMT) for 2005. Enter the amount from line 14 of the 2005 Form 4626
- Minimum tax credit carryforward from 2005. Enter the amount from line 9 of the 2005 Form 8827
- Enter the total of any 2005 unallowed nonconventional source fuel credit and 2005 unallowed qualified electric vehicle credit (see instructions)
- Add lines 1, 2, and 3
- Enter the corporation's 2006 regular income tax liability minus allowable tax credits (see instructions)
- Is the corporation a "small corporation" exempt from the AMT for 2006 (see instructions)?
 - Yes. Enter 25% of the excess of line 5 over \$25,000. If line 5 is \$25,000 or less, enter -0-
 - No. Complete Form 4626 for 2006 and enter the tentative minimum tax from line 12
- Subtract line 6 from line 5. If zero or less, enter -0-
- Minimum tax credit. Enter the smaller of line 4 or line 7 here and on Form 1120, Schedule J, line 5d or the appropriate line of the corporation's income tax return. If the corporation had a post-1986 ownership change or has pre-acquisition excess credits, see instructions
- Minimum tax credit carryforward to 2007. Subtract line 8 from line 4. Keep a record of this amount to carry forward and use in future years

Instructions

Section references are to the Internal Revenue Code unless otherwise noted.
Year references are to the corporation's tax year beginning during that year.

Purpose of Form

Corporations use Form 8827 to figure the minimum tax credit, if any, for AMT incurred in prior tax years and to figure any minimum tax credit carryforward.

Who Should File

Form 8827 should be filed by corporations that had:

- An AMT liability in 2005,
- A minimum tax credit carryforward from 2005 to 2006, or
- A nonconventional source fuel credit or qualified electric vehicle credit not allowed for 2005 (see the instructions for line 3).

Line 3

Enter the total of any nonconventional source fuel credit and qualified electric vehicle credit not allowed for 2005 solely because of the tentative minimum tax limitations under sections 29(b)(6)(B) and 30(b)(3)(B).

Line 5

Enter the corporation's 2006 regular income tax liability (as defined in section 26(b)) minus any credits allowed under Chapter 1, Subchapter A, Part IV, subparts B, D, E, and F of the Internal Revenue Code (for example, if you are

filing Form 1120, subtract any credits on Schedule J, lines 5a through 5d, from the amount on Schedule J, line 2).

Line 6

See the 2006 Instructions for Form 4626 to find out if the corporation is treated as a "small corporation" exempt from the AMT for 2006. If the corporation is a "small corporation" exempt from the AMT, see section 38(c)(5) before completing line 6 for special rules that apply to controlled corporate groups, regulated investment companies, and real estate investment trusts.

Line 8

If the corporation had a post-1986 ownership change (as defined in section 382(g)), there may be a limit on the amount of pre-change minimum tax credits that can be applied against the corporation's tax for any tax year ending after the ownership change. See section 383 and the related regulations. To figure the amount of the pre-change credit, the corporation must allocate the credit for the change year between the pre-change period and the post-change period. The corporation must use the same method of allocation (ratable allocation or closing-of-the-books) for purposes of sections 382 and 383. See Regulations section 1.382-6 for details.

Also, there may be a limit on the use of pre-acquisition excess credits of one corporation to offset the tax attributable to recognized built-in gains of another corporation. See section 384 for details.

If either limit applies, attach a computation of the minimum tax credit allowed. Enter that amount on line 8. Write "Sec. 383" or "Sec. 384" on the dotted line to the left of the line 8 entry space.

Paperwork Reduction Act Notice. We ask for the information on this form to carry out the Internal Revenue laws of the United States. You are required to give us the information. We need it to ensure that you are complying with these laws and to allow us to figure and collect the right amount of tax.

You are not required to provide the information requested on a form that is subject to the Paperwork Reduction Act unless the form displays a valid OMB control number. Books or records relating to a form or its instructions must be retained as long as their contents may become material in the administration of any Internal Revenue law. Generally, tax returns and return information are confidential, as required by section 6103.

The time needed to complete and file this form will vary depending on individual circumstances. The estimated average time is 1 hour.

If you have comments concerning the accuracy of this time estimate or suggestions for making this form simpler, we would be happy to hear from you. See the instructions for the tax return with which this form is filed.

Southwest Gas Corporation
Analysis of AMT Credit Relative to Life Insurance Preferences
Supplement to Data Request STF 11-10

	Prior To 1997	1998	1999	2001	2002	2005	Total
AMT Paid	3,247,739	7,175,288	18,722,588	6,360,549	647,026	667,179	36,820,369
Life Insurance Preference	276,076	1 (2,864,392)	1,100,000	1,082,096	336,111	3,200,049	3,129,941
ACE Preference Discount							75%
Net Additive Preferences							<u>2,347,456</u>
AMT Rate							20%
AMT Credit Associated with Life Insurance Preferences							<u>469,491</u>

¹ This amount was estimated based upon the percentage of preferences for 1998-2005 relative to AMT Paid in those same years

241-096

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-96:

Sales of Property. For the test year, for 2007 to date, and the three years preceding the test year, has the Company sold any property which had formerly been included in Plant Held for Future Use or devoted to utility service? If so, for each sale, describe the property sold; state whether, when, and in what manner it had been included in rate base; show the details of how the gain or loss was calculated; indicate when the sale occurred; explain how and whether the Company is amortizing such gain or loss; and show how such amortization was computed.

Respondent: Property Accounting

Response:

During the normal course of business, the Company will retire assets which had been included in gas plant in service and which are sold. The proceeds from these assets, primarily vehicles and power operated equipment, are credited against Account 108 and no gain or loss is calculated.

In November 2003, the Commission authorized Southwest to acquire the gas distribution properties of Black Mountain Gas (BMG). In September 2007, the Company sold land and structures in Cave Creek, Arizona, which had been included in gas plant in service. The property acquired in the BMG acquisition had a net book value of \$1,025,676 at the time of the sale. The land had a net book value of \$502,044 and the structure had a net book value of \$523,632. The net proceeds of the 2007 sale were \$1,433,107, resulting in a gain of \$418,196. This gain was recorded in Account 2530, "Other Deferred Credits". Attached is a schedule showing the calculation of the gain. Historically, the Commission has

(Continued on Page 2)

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Response to STF-1-96: (continued)

amortized, over a multiple-year period, the gain or loss on Southwest's disposition of property previously included in rate base, 50 percent above-the-line to ratepayers and 50 percent below-the-line to shareholders.

Southwest Gas Corporation
Land and Structures
Cave Creek, Arizona

Vintage Year	Asset ID	Amount	Months	Rate 1.84%	Accumulated Reserve 0.001533	Net Book Value
Land						
Jun-04	99004436	502,044.00				
Acquired Assets in Service		<u>502,044.00</u>				
Structures						
Jun-86	86000074	3,787.67				
Jun-89	89000089	9,281.53				
Jun-90	90000082	2,680.02				
Jun-93	93004494	4,583.86				
Jun-94	94006092	190,570.49				
Jun-95	95005662	1,992.16				
Jun-96	96004279	1,050.50				
Jun-97	97004442	1,972.84				
Jun-00	00015484	415,798.00				
Jun-01	01010085	3,510.00				
Jun-02	02004665	6,240.00				
Acquired Assets in Service		<u>641,467.07</u>	46		45,234.97	
Structures						
Retired November 2005						
Jun-87	87000106	780.30				
Jun-88	88000106	775.00				
Jun-99	99004441	72.75				
Jun-03	03012962	851.00				
Acquired Assets Retired		<u>2,479.05</u>	24		91.21	
Structures						
Purchased Assets Since Acquisition						
Apr-04	04001032	21,023.22	41		1,321.37	
Apr-07	07001100	24,044.08	5		184.30	
Sep-07	07002306	15,044.00	0		0.00	
Acquired Assets Accumulated Reserve at Acquisition					120,314.30	
Adjust Reserve for Retirement of Acquired Assets					(2,479.05)	
Total Land and Structures		<u>\$ 1,179,578.29</u>			<u>\$ 164,667.10</u>	<u>\$ 1,014,911.19</u>

Gain on Sale Calculation

Net Proceeds	\$ 1,433,106.96
Net Book Value	<u>1,014,911.19</u>
Gain on Sale	<u>\$ 418,195.77</u>

294-001

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-9
(ACC-STF-9-1 THROUGH ACC-STF-9-21)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 28, 2008

Request No. ACC-STF-9-1:

Sale of property in Cave Creek, Arizona. Please refer to the response to data request STF-1-96. (A) Did Southwest reflect the historical ratemaking treatment of the gain in its filing? If not, explain fully why not. If so, please show exactly where Southwest reflected the gain sharing, and in what amount over what period. (B) Does Southwest agree that the following adjustment would be reasonable to reflect sharing of this gain?

1.	Gain on Sale of Property in Cave Creek, AZ which had been included in gas plant in service	\$ 418,196
2.	Ratepayer sharing percent	50.0%
3.	Ratepayer sharing amount of gain	\$ 209,098
	Normalization period, in years	3
4.	Adjustment to pre-tax NOI for gain sharing	\$ (69,700)

If not, explain fully why not, and show in detail what adjustment Southwest would propose for sharing of this gain.

Respondent: Revenue Requirements

Response:

The accounting for the Cave Creek transaction was recorded in the Company's books in September 2007, four months after the end of the April 2007 test year. The current rate case was filed with the Commission on August 31, 2007.

(Continued on Page 2)

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Response to ACC-STF-9-1: (continued)

Although the sale took place after the test year, the transaction represents the removal of assets that were included in the test year. Consistent with other Company adjustments, such as wage increases effective after April 2007, applicable to employee salary levels at April 2007, it is reasonable to address the Cave Creek facilities recorded on the Company's books at the end of the test year. It has been the Company's experience, in Arizona, to recover the fifty percent of the gains/losses on the disposition of assets and pass on to the ratepayer the remaining fifty percent. The calculation included as part of the data request appears to be computed correctly and the fifty percent allocation is consistent with prior Commission decisions on gains/losses.

298-015

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 THROUGH ACC-STF-11-15)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 3, 2008

Request No. ACC-STF-11-15:

Payroll taxes. (a) Please identify all payroll tax expense in the test year relating to Management Incentive Program expense. (b) Please identify all payroll tax expense in the test year relating to stock-based compensation expense. (c) Please identify all payroll tax expense in the test year relating to expensed overtime pay. (d) If exact amounts for a, b, and c are not available, provide the Company's best estimates and show in detail how such estimates were derived. (e) Please provide complete supporting calculations and workpapers for parts a through d.

Respondent: Revenue Requirements

Response:

Southwest's annualized labor (as shown in WP Schedule C-2, Adj. No. 3) does not include Management Incentive Program compensation or stock-based compensation. Therefore, the cost of service does not include annualized payroll taxes related to these two items of compensation.

Southwest's best estimate of the payroll taxes for overtime is on the attached worksheet. Southwest assumes that all overtime is subject to FICA and Medicare taxes, but there is no additional FUI and SUI expense since the tax base factors of \$7,000 (Arizona and Federal) or \$24,600 (Nevada) are hit by the regular time pay of all employees. The System Allocable amount is shown net of MMF and 4-Factor to Arizona.

**SOUTHWEST GAS CORPORATION
ARIZONA
FICA AND MEDICARE FOR OVERTIME PAY**

Line No.	Description (a)	Arizona (b)	Corporate Direct Arizona (c)	System Allocable (d)	Line No.
Annualized FICA					
1	Annualized Overtime	\$ 6,918,537	\$ 27,565	\$ 283,422	1
2	Indirect Time %	13.11%	12.95%	12.95%	2
3	Net Annualized Overtime	\$ 6,011,408	\$ 23,995	\$ 246,720	3
4	FICA rate	6.20%	6.20%	6.20%	4
5	Total Annualized FICA	\$ 372,707	\$ 1,488	\$ 15,297	5
Annualized Medicare					
6	Net Annualized Overtime	\$ 6,011,408	\$ 23,995	\$ 246,720	6
7	Medicare Rate	1.45%	1.45%	1.45%	7
8	Total Annualized Medicare	\$ 87,165	\$ 348	\$ 3,577	8
9	Annualized FICA and Medicare on Overtime	\$ 459,873	\$ 1,836	\$ 18,874	9
10	MMF			3.96%	10

FICA

v8m01l

241-049

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-49:

Employee Benefits.

- a List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to SWG.
- b Specifically identify the cost of any SERP or similar programs directly charged or allocated.
- c State the cost by program, of each retirement program directly charged or allocated.
- d Provide the incentive compensation program financial performance goals for 2005, 2006 and 2007.
- e For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.
- f Provide the incentive compensation program in effect in each year, 2005, 2006 and 2007.
- g Show in detail how any special recognition awards recorded in the test year were determined.

Respondent: Human Resources

Response:

- a List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to SWG.

(Continued on Page 2)

241-049

Page 2

Response to STF-1-49: (continued)

Basic Retirement Plan

All employees, including executives, participate in the Company's non-contributory, defined benefit retirement plan (BRP). Benefits are based on an employee's years of service, up to a maximum of 52.5% of the 12-month average of the employee's highest five consecutive years' salaries, excluding bonuses, within the final 10 years of service. The maximum benefit is reached after 30 years of service, the employee must be at least 55 years old to participate in the plan, and some reductions may apply depending on the age and years of service at the time of retirement. In order for contributions to the BRP to be deductible for federal income taxes, for 2007, the maximum annual compensation that can be considered in determining benefits under the basic plan is \$225,000. For future years, the maximum annual compensation will be adjusted to reflect changes in the cost of living as established by the Internal Revenue Service.

Supplemental Employee Retirement Plan (SERP)

Executives also participate in the Company's supplemental retirement plan. Benefits from the plan, when added to the benefits received under the BRP, will equal 60% of annual compensation for senior executives and 50% of annual compensation for all others. Annual compensation is defined as the 12-month average of the highest 36 months of salary. Those who were officers prior to 1991, may retire once they reach age 55 with a minimum of 10 years of service, however, some reductions may apply. All other officers must be at least 55 with 20 or more years of service to receive retirement benefits, and some reductions may apply, depending on the age and years of service at the retirement date.

The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e., participants are general creditors of the corporation). SERP benefits are common in the utility industry.

Executive Deferral Plan

Under the Executive Deferral Plan (EDP), executives at the vice president level and above (officers) may defer up to 100% of their annual compensation and 100% of their cash incentive awards. As a part of this plan, the Company provides matching contributions that parallel the contributions made under the Company's 401(k) plan, which is available to all employees, equal to one-half the deferred amount up to 6% of their annual salary. Officers do not receive a Company match under the 401(k) plan. Pre-selected payouts begin six months after the retirement date.

(Continued on Page 3)

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Response to STF-1-49: (continued)

The EDP is an unqualified plan and, as such, participant balances are not guaranteed. Various types of deferred compensation plans are common in the utility industry.

Management Incentive Plan

The Management Incentive Plan (MIP) provides variable compensation to executives for the achievement of specific goals and benchmarks important to both the short-term and long-term success of the Company. The MIP award is at risk each year based on performance relative to five measures. The five performance measures used to determine the total award under the MIP are as follows:

Three absolute measures include:

- 3-year weighted return on equity
- Customer to employee ratio
- Customer satisfaction survey result

Two relative measures:

- Current return on equity versus peers
- Customer-to-employee ratio versus peers

Each measurement has a threshold, a target and a maximum, and, at target, contributes 20 percent toward the total award for the year. An award under a specific criteria may be given within a range from 70 percent, at threshold, to 140 percent, at maximum. Performance below the threshold results in no award under a specific criteria. There is no incremental value for performance over the maximum for any of the five criteria. In summary, an award can range from 0 percent to 140 percent of the stated MIP opportunity. In any year where the corporate dividend is reduced, there is no MIP award given.

40 percent of the total award earned under the MIP is paid in cash immediately following the financial close of the most recent calendar year. The remaining 60 percent is awarded through the issuance of performance shares, which are issued to the executives and key management employees three years in the future. The longer-term performance shares act as a retention tool while aligning the interests of executives/key management employees, shareholders, and customers.

The MIP award opportunity is measured as a percentage of base salary and varies by title, as follows:

(Continued on Page 4)

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Response to STF-1-49: (continued)

- CEO	115%
- President	100%
- Executive VP	90%
- Senior VP	75%
- VP	50%
- Director/Senior Manager (non-officers)	30%

Equity Compensation

The Stock Incentive Plan (SIP), in place since 1996, made its final option award distribution in July 2006. In May 2007, the SIP was replaced by the Restricted Stock/Unit Plan (RSP).

The RSP is available to officers and other key management employees. The RSP award opportunity is measured as a percentage of base salary and varies by title, as follows:

Position	% of Year-End Base Salaries	Award Range (%)
CEO	45	22.5 to 67.5
President	30	15.0 to 45.0
Executive VP	25	12.5 to 37.5
Senior VP	20	10.0 to 30.0
VP	15	7.5 to 22.5
Other Participants	10	5.0 to 15.0

As a measurement of long-term sustained performance, the average MIP award over the three-year period ending before the award date will be the criteria that will be used in calculating awards for officers and key management employees under the RSP. Awards granted pursuant to the RSP will range from 50 to 150 percent of the target for each participant. The minimum three-year average MIP payout percentage required to receive an award under the RSP will be 90 percent. The dollar amount of an award received under the RSP will be converted to restricted share units using the market price on the date such awards are approved by the Board of Directors. The awards will vest over a three-year period with 40 percent for the first year and 30 percent for the second and third years.

Officers also participate in all of the general employee benefit programs, including: health care, life insurance, disability insurance, vacation, and other optional programs.

(Continued on Page 5)

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Response to STF-1-49: (continued)

Employees Investment Plan/401(k) - The Southwest Gas Corporation Employees' Investment Plan (EIP) is a qualified defined contribution plan that provides a retirement savings mechanism by allowing tax-deferred contributions and the tax-deferred growth of earnings. As a part of the plan, the Company provides matching contributions equal to one-half the deferred amount up to 6% of the contributing employee's annual salary. Employees control how savings are invested by investing in any of the investment options the EIP offers. Officers of Southwest Gas may invest in the EIP, but they are not eligible to receive a Company match in the EIP.

Special Incentive Program - The program has been provided in each of the last several years to reward and recognize exempt employees who make outstanding contributions to the Company. The program is designed for exempt (salaried) employees only who do not qualify for the Management Incentive Plan (MIP).

Awards are limited to 15% of the eligible population. To qualify, an employee has to be recommended, in writing, by an officer. The recommendation must be based on a significant work contribution during the prior year. (Length of service or working long hours are not considered.) All nominations are then reviewed by the appropriate senior officer and the CEO for final approval. Awards range from \$500 to \$2,500.

This program provides management with a tool with which to recognize people who go over and above what is required in their daily job assignments and provide value to the Company and its customers.

b Specifically identify the cost of any SERP or similar programs directly charged or allocated.

The cost of SERP is on WP Schedule C-2, Adj. No. 3, Sheet 8, Line 11. Column B has the total cost to Southwest, Columns C and D have the cost directly attributable to Arizona, and Column F has the System Allocable amount, which is allocated to Arizona with the 4-Factor.

c State the cost by program, of each retirement program directly charged or allocated.

The cost of the BRP is on WP Schedule C-2, Adj. No. 3, Sheet 8, Line 1, the cost for Deferred Compensation (referred to above as EDP) is on Line 12, and the

(Continued on Page 6)

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Response to STF-1-49: (continued)

cost of the 401(k) plan (or Employee Investment Plan) is on Line 2. Column B has the total cost to Southwest, Columns C and D have the cost directly attributable to Arizona, and Column F has the System Allocable amount, which is allocated to Arizona with the 4-Factor.

- d Provide the incentive compensation program financial performance goals for 2005, 2006 and 2007.**

Please see the attached spreadsheet.

- e For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.**

Please see the attached spreadsheet.

- f Provide the incentive compensation program in effect in each year, 2005, 2006 and 2007.**

Copies of the Management Incentive Plan booklet are attached.

- g Show in detail how any special recognition awards recorded in the test year were determined.**

Please see the paragraph on Special Incentive Program in item a. above.

**MIP Measure Analysis
2002 through 2006**

MIP Performance Goals and Actual Results

MEASUREMENT	PY 2006	PY 2005	PY 2004
3-yr. weighted ROE			
target:	6.99	5.31	6.46
earned:	8.0	8.0	8.0
x 20% weight	87.375	66.375	80.8
	17.48	0.00	16.16
Customer/Employee Ratio:			
target:	706	661	633
earned:	591	574	557
x 20% weight	140.0	140.0	140.0
	28.00	28.00	28.00
Customer Service Satisfaction: (percent)			
target:	94.0	93.0	93.0
earned:	85.0	85.0	85.0
x 20% weight	136.0	132.0	132.0
	27.20	26.40	26.40
ROE vs. peers: (percentile)			
target:	53	6	43
earned:	50	50	50
x 20% weight	104.8	0.0	91.6
	20.96	0.00	18.32
Customer/Employee vs peers: (percentile)			
target:	70	87	88
earned:	76	76	76
x 20% weight	92.8	131.9	134.8
	18.56	26.38	26.96
TOTAL (percent of target)	112	81	116

241-087

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-87:

Precedent. Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

Respondent: Revenue Requirements

Response:

Southwest is requesting full cost recovery of its Management Incentive Program and Supplemental Executive Retirement Plan. Please see the testimony of Ms. Laura Hobbs.

Southwest is requesting to recover the test year costs of its Transmission Integrity Management Program (TRIMP) in base rates, and eliminate the TRIMP surcharge. This appears to be consistent with the recent Commission decision in the Unisource (UNS) Gas general rate case. For a discussion of this change, please see the testimony of Mr. Robert Mashas.

Southwest is requesting full recovery of its Sarbanes-Oxley (SOX) compliance costs. Since the Commission has not disallowed ("shared") SOX costs in the more recent UNS and Arizona Public Service Company general rate cases, Southwest did not present testimony on this change since Southwest's treatment of these

(Continued on Page 2)

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Response to STF-1-87: (continued)

costs is consistent with recent Commission orders in energy utility general rate proceedings.

In Southwest's last general rate case, the Commission directed Southwest to provide detailed information regarding the duties of Service Planning and Key Accounts Management employees in this rate case to determine if any disallowance is appropriate. Please see the testimony of Ms. Randi Aldridge for this information.

295-012

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-10
(ACC-STF-10-1 THROUGH ACC-STF-10-26)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 29, 2008

Request No. ACC-STF-10-12:

Stock based compensation and stock option expense. (a) Please identify, by account, all expense for stock based compensation and stock option expense in the test year ending April 30, 2007. (b) Please identify, by account, all expense for stock based compensation and stock option expense in each year, 2005, 2006 and 2007. (c) Please show in detail how the \$3.3 million of total stock-based compensation expense recognized in the consolidated statement of income for the year ending December 31, 2006 was allocated to Southwest's Arizona operations.

Respondent: Revenue Requirements

Response:

All expense related to stock-based compensation and stock option expense is in FERC Account 920.

a. and b. Please refer to the attached file. Amounts listed in the attachment are prior to allocation to Arizona.

c. Please refer to the Company's supplemental response provided in response to STF-6-41.

SOUTHWEST GAS CORPORATION
STOCK-BASED COMPENSATION EXPENSE
IN RESPONSE TO STF-10-12

	<u>MIP Stock</u>	<u>Stock Option Expense</u>		<u>RSUP</u>		<u>Total Stock Expense</u>
5/06 - 4/07	\$ 3,587,416	\$ 1,507,520	(a)	\$ -		\$ 5,094,936
2005	4,115,000	-		-		\$ 4,115,000
2006	3,136,306	1,493,694	(a)	-		\$ 4,630,000
2007	3,631,939	879,809	(a)	1,192,560	(a)	\$ 5,704,308

(a) Beginning in 2006, stock options were required to be expensed. In May 2007, a restricted stock unit plan replaced the stock option plan (and were also required to be expensed). Stock-based compensation is expensed over a three-year vesting period. Grants to retirement eligible employees are immediately expensed.



MEMORANDUM

To: Roy Centrella
From: Dana Van Pelt / Kathy Beavers
Date: December 29, 2005
Subject: **SFAS No. 123 (Revised 2004) Share-Based Payment**

Executive Summary

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 123 (revised 2004), "Share-Based Payment." SFAS No. 123 (revised 2004) is a revision of SFAS No. 123, "Accounting for Stock-Based Compensation" and supersedes Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." SFAS No. 123 (revised 2004) changes the accounting for employee stock options by requiring that companies record the fair value of the awards that they grant as an expense in the income statement. The following paragraphs summarize the major provisions of the new standard and their impact to the Company.

The Company will adopt the new standard under the modified prospective application, whereby expense will be recognized for new awards granted after the effective date (January 1, 2006) and for any unvested portion of awards granted prior to the effective date.

SIP Awards – Under APB 25, the Company disclosed the effect on net income and earnings per share if the Company had applied the provisions of SFAS No. 123 to its MIP and SIP awards. Beginning with the first quarter of 2006, the Company will recognize compensation expense for the SIP as well as the MIP in the financial statements. SIP expense will be based on the fair value of the options on their grant date. Unvested SIP awards will be expensed based on assumptions previously disclosed in financial statements.

MIP Awards – Under APB 25, expense for MIP awards was adjusted for fluctuations in stock price and dividends paid on unvested shares during the vesting period. Under the new standard, the fair value of new MIP awards will be fixed on the grant date and expensed ratably over the three year vesting period. Dividend shares will not impact expense, but will be recorded in equity when issued. Existing unvested MIP awards will also be fixed but the value will be based on the share price on the date of adoption (January 1, 2006).

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Awards to Retirement Eligible Employees – Historically, the Company has expensed stock awards over service to the stated vesting date, with cost recognition accelerated only if the employee retires. Upon adoption of SFAS No. 123 (revised 2004), the Company will accelerate expense recognition for new awards to retirement-eligible employees. Acceleration of the vesting period will only affect new or modified awards and will be classified consistent with other stock compensation (i.e. not as a cumulative effect of a change in accounting principle). Awards that are not vested upon adoption of the new standard will continue to be expensed over service to the stated (expected) vesting date. The table below illustrates how the expense for an MIP award granted to a retirement-eligible employee after January 1, 2006 will be accelerated under the new standard. The example assumes that the employee has ten years of service, the fair value of the restricted shares on the grant date is \$5,000 and the shares vest over 3 years.

Employee Age	20X5	20X6	20X7
50	\$ 1,667	\$ 1,667	\$ 1,667
53	\$ 2,500	\$ 2,500	\$ -
55	\$ 5,000	\$ -	\$ -

Following is a more in depth discussion of the accounting and the extensive 2006 disclosure requirements of the new standard.

Background

The Company has two stock-based compensation plans. These plans are accounted for in accordance with APB Opinion No. 25.

Under one plan, the stock incentive plan ("SIP"), the Company may grant options to purchase shares of common stock to key employees and outside directors. Each option has an exercise price equal to the market price of Company common stock on the date of grant and a maximum term of ten years. The options vest 40 percent at the end of year one and 30 percent at the end of years two and three.

In addition to the SIP, the Company has a management incentive plan ("MIP") through which it may issue restricted stock in the form of performance shares to encourage key employees to remain in its employment to achieve long-term performance goals. The performance shares vest after three years from issuance and are subject to a final adjustment as determined by the Board of Directors.

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Additionally, awards issued under both plans vest upon retirement. A retiree has two years to exercise their vested options. If an employee terminates employment prior to exercising vested options, those options are cancelled.

The purpose of this paper is to address SFAS No. 123 (revised 2004) as it applies to the Company. Income tax accounting considerations related to the standard will be addressed in a separate memo.

Summary

SFAS No. 123 (revised 2004) establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement eliminates the alternative to use APB Opinion No. 25 and the intrinsic value method of accounting. The following are some of the major differences between SFAS No. 123 (revised 2004) and the original SFAS No. 123:

- SFAS No. 123 (revised 2004) requires entities to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant-date fair value of those awards (with limited exceptions). SFAS No. 123 allowed companies to follow the intrinsic value method described in APB Opinion No. 25 and disclose, rather than recognize, the compensation expense the company would have been required to record if it had adopted SFAS No. 123.
- SFAS No. 123 (revised 2004) requires that the cost be recognized over the period during which an employee is required to provide service in exchange for the award—the requisite service period (usually the vesting period or date at which the employee becomes eligible for retirement, whichever occurs first). SFAS No. 123 allowed companies to recognize compensation cost over the explicit service period (up to the date of actual retirement).
- Under SFAS No. 123 (revised 2004), companies are required to estimate the rate at which equity award forfeitures are expected to occur. No compensation cost is recognized for equity instruments that were forfeited due to non-performance of the requisite service period. SFAS No. 123 permitted companies to account for forfeitures as they happen.
- SFAS No. 123 (revised 2004) amends SFAS No. 95, "Statement of Cash Flows", to change the way excess tax benefits are displayed in the statement of cash flows. A company will be required to use a "gross" approach to recognize as a financing cash inflow (rather than a reduction of taxes paid) its

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excess tax benefits from exercised awards and will not be allowed to net any tax-benefit deficiencies against excess tax benefits.

The following table illustrates the effect on historical net income if the Company had applied the fair value recognition provisions of SFAS No. 123 to its stock-based employee compensation (thousands of dollars):

	<u>2004</u>	<u>2003</u>	<u>2002</u>
Stock-based employee compensation expense included in reported net income, net of related tax benefits previously recognized under APB 25:			
MIP	1,825	2,438	1,783
SIP	-	-	-
Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax benefits:			
MIP	(1,468)	(2,434)	(1,551)
SIP	(490)	(486)	(473)
Subtotal	<u>(1,958)</u>	<u>(2,920)</u>	<u>(2,024)</u>
Total effect on net income	<u>\$ (133)</u>	<u>\$ (482)</u>	<u>\$ (241)</u>

Valuation

SFAS No. 123 (revised 2004) provides flexibility with respect to developing the underlying assumptions that are used in a company's estimate of fair value as determined by an option pricing model. Regardless of which valuation method a company chooses, the company must estimate, in good faith, the fair value of stock-based compensation and provide transparent disclosure about the accounting and financial reporting.

Valuation Techniques

SFAS No. 123 (revised 2004) requires that the fair value of equity awards be estimated using a valuation technique that:

- is applied in a manner consistent with the fair value measurement objective and the other requirements of SFAS No. 123 (revised 2004),
- is based on established principles of financial economic theory and is generally applied in that field, and
- reflects all substantive characteristics of the instrument (except for those explicitly excluded, such as vesting conditions and reload features).

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SFAS No 123 (revised 2004) does not specify a preference for a particular type of valuation model but does require the use of a valuation technique or model that meets the above objectives.

Expected Volatility

Expected volatility is the expected fluctuation in the price of the underlying stock during the expected term or contractual term of the option (depending on the valuation technique utilized). To meet the fair value measurement objective of SFAS No. 123 (revised 2004), management must estimate the expected volatility of the Company's share price. The objective of estimating volatility under SFAS No. 123 (revised 2004) is to determine which assumption about expected volatility is likely to be used by marketplace participants when they are pricing an option.

Expected Term

SFAS No. 123 (revised 2004) requires that when stock options are being valued using the Black-Scholes model, the company should use the options' expected term instead of its contractual term.

Staff Accounting Bulletin ("SAB") 107 provides a simplified method for determining the expected term of "plain vanilla" options in certain circumstances. Under this method, the expected term would equal the vesting term plus the contractual term divided by two. Under SAB 107, a stock option qualifies as a "plain vanilla" option when:

- It is granted at the money.
- Exercisability is conditional only on completing the service condition through the vesting date.
- Employees who terminate their service prior to vesting must forfeit the options.
- Employees who terminate their service after vesting are granted a limited time to exercise their options (typically 30-90 days).
- Stock options are nontransferable and nonhedgeable.

This simplified or "safe harbor" method may not be used for grants made after December 31, 2007.

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Transition

For public companies, SFAS No. 123 (revised 2004) allows two alternative transition methods:

- Modified prospective application ("MPA")
- Modified retrospective application ("MRA")

A public company that uses the MPA method will not restate its prior financial statements. Instead, the company will apply SFAS No. 123 (revised 2004) for

- New awards granted after the adoption of SFAS No. 123 (revised 2004),
- Any portion of awards that were granted after December 15, 1994 and have not vested by the date the company adopts SFAS No. 123 (revised 2004), and
- Any outstanding liability awards.

Measurement and attribution of compensation cost for awards that are outstanding and classified as equity at the adoption date of SFAS No. 123 (revised 2004) should be based on the original grant-date fair value of those awards and the same attribution method that, under the provisions of SFAS No. 123, the company previously used for the purpose of either recognition or pro forma disclosure. However, the Company should discontinue its past practice of recognizing forfeitures only as they occur.

Under the MRA method, a company will restate its prior financial statements to include the amounts that the company previously reported as pro forma disclosures under the original provisions of SFAS No. 123. The measurement and attribution of compensation cost for equity-classified awards that the company granted for the fiscal years beginning after December 15, 1994 are based on the grant-date fair value of those awards and on the same attribution method that was previously used for pro forma disclosures.

Application to Southwest Gas

In April 2005, the U.S. Securities and Exchange Commission ("SEC") amended the compliance dates for SFAS No. 123 (revised 2004). The provisions of the statement are effective for the Company beginning January 2006. It is anticipated that the Company will apply the MPA transition method. The MPA

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appears to be the better choice for the Company, as there is no requirement for the restatement of prior periods.

Transition for MIP Awards

Currently under APB Opinion No. 25 ("APB 25"), compensation expense is only recognized in the financial statements for restricted shares issued from the MIP. Under APB 25, restricted stock (MIP) awards qualified as "liability awards" and are remeasured at fair value each reporting period until the award is settled. Remeasurement of fair value takes into consideration periodic fluctuations in the stock price and incremental dividend shares.

Under the new standard, the fair value of new MIP awards will be fixed on the grant date and expensed ratably over the three year vesting period. No adjustments will be made for fluctuations in stock price or dividends paid on unvested shares during the vesting period. Compensation expense will be reversed for any shares that do not vest. Existing unvested MIP awards will also be fixed but the value will be based on the share price on the date of adoption (January 1, 2006).

In accordance with the terms of the plan, the fair value of MIP awards is determined using a five day average share price, as opposed to the share price on the grant date. The use of a five day average price is consistent with the mutual understanding between the Company and the employee regarding the terms of the award. SFAS No. 123 (revised 2004) defines the grant date for an award as the date that an employee begins to benefit from, or be adversely affected by, subsequent changes in the price of the employer's equity shares. That price in this case is equal to the five day average.

Transition for SIP Awards

Under APB 25, the Company currently discloses in its filings with the SEC the effect on net income and earnings per share if the Company had applied the fair value recognition provision of SFAS No. 123 to its stock-based employee compensation, including both MIP and SIP awards. Beginning with the first quarter of 2006, the Company will recognize compensation expense for all new SIP awards equal to the fair value of the options on their grant date. Existing unvested SIP awards will be expensed prospectively using the assumptions previously disclosed in the footnotes. The fair value of the SIP awards is determined using the grant date share price, as opposed to a five day average. Compensation expense for SIP awards will be recognized monthly (based on either the graded vesting or straight-line approach explained further below). If the

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options do not fully vest, compensation expense will be reversed for the current year only.

Retirement Eligible Employees - SEC Staff View

Historically, the Company has expensed stock awards over service to the stated vesting date, with cost recognition accelerated only if the employee retires. Recently, the SEC Staff has clarified that it expects companies to recognize compensation cost from the date of grant through the date the employee first becomes eligible to retire (i.e., the date the employee can receive the award without further service). As a result, upon adoption of SFAS No. 123 (revised 2004), the Company will change its policy and begin recognizing expense immediately for an award issued to an employee who is currently eligible for retirement. This policy change is not required by SFAS No. 123 (revised 2004), but will coincide with its adoption. Generally, employees are eligible for retirement when they reach 55 years old and have 10 years of service. Acceleration of the vesting period will only affect new or modified awards and will be classified consistent with other stock compensation (i.e. not as a cumulative effect of a change in accounting principle). For those awards that are not yet vested upon adoption of the new standard, the remaining unrecognized cost (measured on a fair value basis) is to continue to be expensed based on the prior practice (i.e., recognize remaining cost over service to the stated or expected vesting date).

The table below illustrates how the expense for a MIP award granted to an employee after January 1, 2006 will be accelerated for retirement eligible employees under the new standard. This illustration applies equally to future SIP awards. The example assumes that the employee has ten years of service, the fair value of the restricted shares on the grant date is \$5,000 and the shares vest over 3 years.

Employee Age	20X5	20X6	20X7
50	\$ 1,667	\$ 1,667	\$ 1,667
53	\$ 2,500	\$ 2,500	\$ -
55	\$ 5,000	\$ -	\$ -

The SEC recommends making the following disclosures (both before and after the adoption of SFAS No. 123 (revised 2004)):

- Accounting policy followed under APB Opinion No. 25 and SFAS No. 123 for the recognition of compensation cost for awards that accelerate vesting upon retirement;

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- The accounting policy change that will occur as a result of adopting SFAS No. 123 (revised 2004); and
- The quantitative affect of applying SFAS No. 123 (revised 2004) cost recognition requirements compared to the "old" cost recognition vesting approach, for each income-statement period presented. The Company is in the process of determining this amount and assessing the need to disclose it based on materiality. If material, the disclosure would appear as follows:

	2004	2003	2002
Fair value of stock-based compensation expense under old vesting approach	XXX	XXX	XXX
Fair value of stock-based compensation under accelerated vesting approach	XXX	XXX	XXX
Difference	XXX	XXX	XXX

Valuation

The Company currently uses the Black-Scholes model included in the Bloomberg executive option pricing application which meets the basic valuation requirements of SFAS No. 123 (revised 2004). However, we are in the process of evaluating other valuation models available.

Since the Company issues equity awards with graded vesting (SIP options), under SFAS No. 123 (revised 2004) the Company will need to make a one-time policy election, choosing between two attribution approaches. The first approach is to treat each vesting tranche as a separate award with compensation cost for each award recognized over the vesting period. This approach results in a greater amount of compensation cost recognized in the earlier periods of the grant with a declining amount recognized in later periods. The second approach is to treat the award as a single award for recognition purposes (although the Company may value each tranche separately) and recognize compensation cost on a straight-line basis over the vesting period of the entire award. It is anticipated that the Company will follow the second approach. Regardless of the approach selected, the amount of compensation cost recognized at any date must at least equal the portion of the grant-date value of the award that is vested at that date.

SFAS No. 123 (revised 2004) requires that the recognition of compensation cost ultimately be based on the number of awards whose requisite service period is complete (shares that vest). Therefore, the Company will base initial accruals of

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compensation cost on the number of awards estimated at the grant date that are expected to vest. SIP and MIP forfeitures are unusual and historically insignificant so it is currently assumed that none will occur. The estimated number of awards for which the requisite service is expected to be rendered will need to be revised if subsequent information indicates that the actual number of awards that vest is likely to differ from initial estimates.

The Company has historically considered the effective date for grants of equity instruments to be the date on which those awards are approved by the board of directors. The definition of grant date under SFAS No. 123 (revised 2004) includes criteria for determining that a share-based payment award has been granted. One of the criteria is a mutual understanding by the employer and employee of the key terms and conditions of a share-based payment award. In response to a recent inquiry, the FASB issued a FASB staff position ("FSP") FAS 123(R) - 2 to provide guidance on the application of grant date as defined in SFAS No. 123 (revised 2004). Under the FSP, in determining the grant date of an award subject to SFAS No. 123 (revised 2004), assuming all other criteria have been met, a mutual understanding of the key terms and conditions of an award to individual employees shall be presumed to exist at the date the award is approved by the board of directors if both the following conditions are met:

- The recipient does not have the ability to negotiate the key terms and conditions of the award with the employer; and
- The key terms of the award are expected to be communicated to all of the recipients within a relatively short time period from the date of approval.

Based on the above, the Company will continue to consider the effective date for grants of equity instruments to be the date on which those awards are approved by the board of directors.

Expected Volatility

To meet the fair value measurement objective of SFAS No. 123 (revised 2004), management must estimate the expected volatility of the Company's share price. For all future option grants, the Company will need to consider the following variables when estimating expected volatility:

- The volatility of the stock price over the most recent period equal to the expected term;
- How long the Company's shares have been publicly traded; and

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- The appropriate and regular intervals for price observations.

Expected Term

The Company issues "plain vanilla" options and therefore plans to use the simplified method of calculating the expected term according to SAB 107. As mentioned above, the simplified method is based on the vesting period and the contractual term for each vesting-tranche. The mid-point between the vesting date and the expiration date is used as the expected term under this method.

For all future SIP option grants the Company has calculated the expected term to be approximately six years (see calculation below). The calculation reflects the 40%, 30% 30% vesting in years one through three.

Year 1 40% x 1 =	0.4
Year 2 30% x 2 =	0.6
Year 3 30% x 3 =	0.9
Average vesting	1.9 years
Contratual term	10.0 years
Subtotal	11.9 / 2 = 5.95 years (6 years rounded)

Earnings per Share (EPS)

Unvested restricted stock is generally excluded from the denominator in the computation of basic EPS because the shares have not yet been earned by the employee. Once vested, the shares are included in basic EPS as of the vesting date. Under the new standard, awards to retirement eligible employees will be considered vested for this computation.

The Company should include unvested restricted stock with service conditions in the calculation of diluted EPS using the treasury stock method. If dilutive, the stock would be considered outstanding as of the grant date for diluted EPS computation purposes. If anti-dilutive, it would be excluded from the diluted EPS computation. The anti-dilutive test must be performed for each stock option grant and not for the aggregate of all option grants.

The assumed proceeds under the treasury stock method include:

- The purchase price that the grantee pays, if any (or the exercise price of the stock option);

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- Compensation expense for future service that the Company has not yet recognized; and
- Any windfall tax benefits that would be credited to APIC when the award becomes taxable. If there would be a charge to APIC (i.e., shortfall), such an amount would be a reduction of proceeds.

Journal Entries

SFAS No. 123 (revised 2004) requires that the Company make a one-time cumulative adjustment at the adoption date. The adjustment is necessary since under SFAS No. 123, the Company chose to recognize actual forfeitures when they occurred rather than estimate them at the grant date and subsequently true-up the estimated forfeitures to actual. The cumulative effect adjustment would be recorded using a memo entry in the period of adoption to adjust compensation cost for awards, issued prior to the adoption of SFAS No. 123 (revised 2004), that are not expected to vest. If the Company assumes, based on historical data, that the forfeiture rate is negligible, then no memo entry would be made. Although forfeitures are rare for the Company, a thorough analysis of estimated forfeitures of outstanding awards should be completed prior to the adoption of the standard. If the actual forfeitures of awards granted before the adoption of SFAS No. 123 (revised 2004) exceed (or are less than) the memo entry of expected forfeitures, the difference would be ultimately recognized in the income statement as an adjustment to compensation cost.

SFAS No. 123 (revised 2004) does not require that stock-based compensation cost be presented in a specific line in the income statement. The SEC staff believes that companies should present the expense for employee stock-based compensation in the same line in the financial statements as cash payments to those employees (i.e. operations expense; a portion may also be capitalized as overhead).

Detailed below is a series of proposed journal entries. For simplicity, compensation cost for the Company's two stock-based compensation plans have been combined and the proposal illustrates those entries to be made on an annual (rather than monthly) basis. Tax entries will be addressed in a separate memo.

After estimating the fair value of the equity awards at the measurement date and calculating the total estimated compensation cost, the compensation cost should be allocated over the requisite service period. Note: At the end of the vesting period, the Company will record compensation cost reflecting the number of

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actual forfeitures, and adjust the cumulative expense to reflect the actual number of vested awards.

1) Allocation of compensation cost over requisite service period:

Compensation cost	XXXX
APIC (equity awards)	XXXX

2) Conversion of vested awards into common stock:

Cash	XXXX
APIC (equity awards)	XXXX
Common stock	XXXX
APIC	XXXX

Should the Company revise the estimated compensation cost (due to a change in expected forfeitures), the original fair value of the award is not revised. At that point, the Company should determine the periodic compensation cost based on the revised estimated forfeitures. The change in the estimate is the difference between the revised cumulative amount and the amount already recognized. Going forward, the Company would recognize the revised compensation cost allocation amount over the remaining requisite service period (see entry 1 above).

3) Change in estimate (assuming estimated forfeitures increased):

APIC (equity awards)	XXXX
Compensation cost	XXXX

Liability Awards

Liability awards are required to be remeasured at fair value each reporting period, until the award is settled. SFAS No. 123 (revised 2004) has four key principles regarding when an award should be classified as a liability, with certain exceptions. The Company does not issue any awards that qualify as liability awards under these principals.

The written terms of a stock-based-compensation award are generally the best evidence of whether the substantive terms of an award (e.g., if the employee can choose the form of settlement) indicate that the award is a liability. However, a company's past practice of settlement may outweigh the written terms, resulting in substantive liabilities and, thus, liability classification. Historically, the Company has allowed employees to convert a portion of issued restricted (MIP) shares for

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taxes withheld in excess of statutory limits. As of January 1, 2006, the conversion election will no longer be permitted and the Company will automatically convert a portion of gross shares issued for tax withholding purposes in accordance with statutory limits. Additionally, retirees will no longer receive cash in lieu of shares. These changes will prevent the Company from having to treat stock awards as liability awards. The Company's plans do not require cash settlement upon a change in control or an employee's death or disability.

Financial Statement Disclosure

SFAS No. 123 (revised 2004) and SAB 107 specify the minimum information that a company should disclose for equity awards. The Company currently provides a great deal of information pertaining to the awards in the notes to the consolidated financial statements provided in the annual report and periodic filings with the SEC. In order to meet the disclosure objectives described by SFAS No. 123 (revised 2004) and SAB 107, the Company should also disclose, at a minimum, the material information set out below in its 2006 annual report.

- The method used to measure compensation cost.
- The total intrinsic value of options exercised for each year that an income statement is presented. This will be the amount by which the market price of the stock exceeds the exercise price of the option for each option exercised during the year. For example, an option with an exercise price of \$20 on a stock whose current market price is \$25 has an intrinsic value of \$5.
- The total fair value of shares vested during the year for each year that an income statement is presented.
- The number, weighted-average exercise price, aggregate intrinsic value, and weighted average remaining contractual term of options currently exercisable for options expected to vest at the date of the latest statement of financial position.
- Aggregate intrinsic value and weighted average remaining contractual term of options currently exercisable for fully vested options at the date of the latest statement of financial position.
- How the expected term of the options was incorporated into the fair value determination (for each year in which an income statement is provided).

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- How the contractual term of the instruments and employees' expected exercise and post-vesting termination behavior were incorporated into the fair value determination (for each year in which an income statement is provided).
- Estimated volatility, the method used to estimate the volatility of SWG's awards, the range of expected volatilities used (if different over the contractual term) and the weighted average expected volatility (for each year in which an income statement is provided).
- If different dividend rates are used over the contractual term, the range of and the weighted average of expected dividends (for each year in which an income statement is provided).
- If different risk-free rates are used, the range of risk-free rates used at the time of grant (for each year in which an income statement is provided). (Example – the risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant.)
- Discount rate and method used to estimate post-vesting restrictions (for each year in which an income statement is provided).
- The total recognized income tax benefit related to the compensation cost recognized in net income and the total compensation cost capitalized as a part of the cost of an asset (for each year in which an income statement is provided).
- As of the latest balance sheet date presented, the total compensation cost related to nonvested awards not yet recognized and the weighted average period over which it is expected to be recognized (for each year in which an income statement is provided).
- The amount of cash received from the exercise of options.
- The windfall tax benefits realized from stock options exercised during the year.
- The amount of cash used to settle equity instruments granted under share-based payment arrangements.

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- A description of the policy, if any, for issuing shares upon share option exercise including the source of those shares, new shares or treasury shares. If as a result of its policy, the Company expects to repurchase shares in the following annual period, an estimate of shares to be repurchased during that period should be disclosed.

Prior to the adoption of SFAS No. 123 (revised 2004), the Company should disclose its accounting policy for the recognition of compensation cost for awards subject to acceleration of vesting upon retirement, and that the policy will be changed upon the adoption of SFAS No. 123 (revised 2004).

Upon adopting SFAS No. 123 (revised 2004), the Company will disclose the impact of the adoption in its first quarter Form 10-Q. The pro forma disclosures required for interim periods under SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure" will continue to be made until all such interim periods are reported on a comparable basis.

The Company should also consider including in MD&A material qualitative and quantitative information about any of the following, as well as other information that could affect comparability of financial statements from period to period:

- Transition method selected (e.g., MPA or MRA) and the resulting financial statement impact in current and future reporting periods;
- Method utilized by the Company to account for share-based payment arrangements in periods prior to the adoption of SFAS No. 123 (revised 2004) and the impact, or lack thereof, on the prior period financial statements;
- Modifications made to outstanding share options prior to the adoption of SFAS No. 123 (revised 2004) and the reason(s) for the modification; (*None are anticipated*)
- Differences in valuation methodologies or assumptions compared to those that were used in estimating the fair value of share options under SFAS No. 123; (*None are anticipated*)
- A discussion of the one-time effect, if any, of the adoption of SFAS No. 123 (revised 2004), such as any cumulative adjustments recorded in the financial statements; (*No adjustment is anticipated*)

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- Total compensation cost related to nonvested awards not yet recognized and the weighted average period over which it is expected to be recognized.

During 2006, the Accounting Department will draft an addendum to this white paper which provides the disclosures required for the 2006 Annual Report to Shareholders.

sw

- c. George Biehl
Greg Peterson
Dave Randall

294-018

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-9
(ACC-STF-9-1 THROUGH ACC-STF-9-21)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 28, 2008

Request No. ACC-STF-9-18:

TRIMP Surcharge. Refer to Mr. Mashas' Direct Testimony at page 19, lines 20-23 where it states The Company proposes to cease charging TRIMP-related expense to Account 182.3 the month the proposed new rates take effect. The surcharge will discontinue once the deferred balance in Account 182.3 reaches zero. (A) Please identify, quantify and explain fully and in detail when the Company anticipates the deferred balance in Account 182.3 will reach zero. (B) Please show the TRIMP amortization schedule being used by the Company. (C) Please show how the reach zero point has been coordinated with SWG's proposal to cease charging the TRIMP-related expense to Account 182.3 once the proposed new rates take effect.

Respondent: Revenue Requirements

Response:

The Company charges 100 percent of TRIMP costs to deferral Account 182.3. On a one month lag, 50 percent of the prior month expense is credited to Account 182.3 and debited to Account 887.0, Maintenance of Mains. The 50 percent that remains in Account 182.3 is recovered from customers through revenues received via the DOT TRIMP surcharge. During the 12 months ended April 30, 2007, 100 percent of the TRIMP expense incurred totaled \$920,914. As the Company credits Account 182.3 for TRIMP revenues received, a debit to Account 407.3, Regulatory Amortizations, is recorded in a like amount.

A) Attached is a schedule showing the monthly TRIMP expense experienced, the 50 percent deferred and the dollars recovered through the DOT-TRIMP surcharge from inception through January 2008. As of January 2008, the balance in Account 182.3 was \$1,427,646. The Company projects this balance to be \$1,427,329 and \$1,375,007 by April 2008. In Decision No. 68487, the Commission adopted Staff's

(Continued on Page 2)

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Response to ACC-STF-9-18: (continued)

position on TRIMP, including an implementation of a DOT-TRIMP surcharge that would remain in effect for 36 months from the effective date (March 1, 2006) of rates in that proceeding. As such, the TRIMP surcharge will cease on February 28, 2009. The Company was directed to file with the Commission to change the TRIMP surcharge effective each May 1. The Company will file with the Commission on or about March 31, 2008, a proposed rate that would clear the projected deferred balance at April 30, 2008 and 50 percent of the projected expense to be experienced from May 1, 2008 through February 28, 2009.

B) Attached is a file showing all debit and credit activity that has occurred in Account 182.3, Deferred TRIMP from inception through January 31, 2008 and the projected activity through February 28, 2009. Without a change in recovery process in this proceeding, the Company would bear all cost of complying with the federally-mandated TRIMP program beginning March 1, 2009.

The proposed rate change calculated in the attached schedules would change the TRIMP surcharge from the current \$0.00072 to \$0.00294. The monthly impact on a residential customer for the months of May 2008 through February 2009 would average \$0.08 per month.

C) Attached is a file coordinating the Company's rate case proposal to recover TRIMP cost in base rates and cease deferral of such costs on November 1, 2008, provided that rates in this proceeding go into effect on that date. Should the effective date differ or the Commission's decision deviate from the Company's proposal, then the amount and timing would change accordingly

ATTACHMENT
STF-9-18

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-18
TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TRIMP)
RECOVERY OF ACCOUNT 182.3 BALANCE @ APRIL 30, 2008 PLUS
50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATE EFFECTIVE MAY 1, 2008

Month	2004					2005				
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery	Ending Balance	Beginning Balance	100% Cost	50% Write-Off	\$ 0.00072 Recovery
January	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ 414,227	\$ 3,288	\$ -	\$ -	\$ -
February	-	-	-	-	-	417,515	10,172	-	-	-
March	-	-	-	-	-	427,687	112,724	-	-	-
April	-	-	-	-	-	540,411	74,841	-	-	-
May	-	472	-	-	-	615,251	34,497	-	-	-
June	472	8,545	-	-	-	649,748	153,865	-	-	-
July	7,016	5,129	-	-	-	803,613	59,016	-	-	-
August	12,146	34,505	-	-	-	862,629	37,808	-	-	-
September	46,651	26,728	-	-	-	900,437	74,315	-	-	-
October	73,378	43,459	-	-	-	974,752	57,343	-	-	-
November	116,837	47,646	-	-	-	1,032,095	81,835	-	-	-
December	164,483	249,744	-	-	-	1,113,930	116,931	-	-	-

Month	2006					2007				
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery	Ending Balance	Beginning Balance	100% Cost	50% Write-Off	\$ 0.00072 Recovery
January	\$ 1,230,860	\$ 3,399	\$ -	\$ -	\$ -	\$ 1,234,260	\$ 679,585	\$ 1,897	\$ (92,152)	\$ (90,809)
February	1,346,445	112,185	-	-	-	1,346,445	498,320	89,940	(848)	(77,636)
March	728,371	89,028	(57,792)	(615,430)	(33,880)	728,371	508,776	51,725	(44,970)	(55,745)
April	673,741	78,761	(36,165)	-	(53,530)	673,741	460,787	295,845	(25,863)	(36,334)
May	677,103	25,799	(39,380)	-	(41,873)	621,648	730,094	219,061	(147,922)	(35,480)
June	621,648	11,717	(12,899)	-	(32,941)	587,524	1,150,662	563,459	(109,530)	(33,361)
July	587,524	25,739	(5,856)	-	(31,285)	576,119	997,893	382,430	(80,935)	(32,385)
August	576,119	61,416	(12,866)	-	(11,353)	613,312	1,267,003	606,096	(191,216)	(30,794)
September	613,312	40,790	(30,708)	-	(32,705)	590,690	1,651,090	211,300	(303,048)	(20,990)
October	590,690	53,182	(20,395)	-	(38,631)	584,845	1,538,352	145,226	(105,650)	(27,071)
November	584,845	184,305	(26,591)	-	(62,974)	679,585	1,550,858	17,513	(72,613)	(45,145)
December										

[1] To write off 50% of 2004 & 2005 program costs incurred prior to implementing the deferred accounting and monthly surcharge in March 2006.

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-18
TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TRIMP)

RECOVERY OF ACCOUNT 182.3 BALANCE @ APRIL 30, 2008 PLUS
50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATE EFFECTIVE MAY 1, 2008

Month	2008					2009				
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00294 Recovery	Ending Balance	Beginning Balance	100% Cost	50% Write-Off	\$ 0.00294 Recovery
January [2]	\$ 1,450,812	\$ 63,984	\$ (8,756)	-	\$ (78,193)	\$ 1,427,846	\$ 528,520	\$ 76,743	\$ (38,371)	\$ (320,247)
February	1,427,846	76,743	(31,992)	-	(70,356)	1,402,041	528,520	76,743	(38,371)	(320,247)
March	1,402,041	76,743	(38,371)	-	(59,919)	1,380,493	(2,272)	76,743	-	-
April	1,380,493	76,743	(38,371)	-	(43,857)	1,375,007	74,471	76,743	-	-
May	1,375,007	76,743	(38,371)	-	(146,813)	1,266,566	151,214	76,743	-	-
June	1,266,566	76,743	(38,371)	-	(122,289)	1,182,648	227,956	76,743	-	-
July	1,182,648	76,743	(38,371)	-	(114,154)	1,068,865	304,699	76,743	-	-
August	1,068,865	76,743	(38,371)	-	(107,741)	963,697	381,442	76,743	-	-
September	1,037,496	76,743	(38,371)	-	(112,170)	878,784	458,185	76,743	-	-
October	963,697	76,743	(38,371)	-	(123,285)	878,784	534,928	76,743	-	-
November	878,784	76,743	(38,371)	-	(159,478)	757,677	611,670	76,743	-	-
December	757,677	76,743	(38,371)	-	(287,528)	528,520	688,413	76,743	-	-
January	\$ 765,156	\$ 76,743	\$ -	\$ -	\$ -	\$ 841,899	\$ 1,686,070	\$ 76,743	\$ -	\$ -
February	841,899	76,743	-	-	-	918,642	1,762,813	76,743	-	-
March	918,642	76,743	-	-	-	995,385	1,839,556	76,743	-	-
April	995,385	76,743	-	-	-	1,072,127	1,916,299	76,743	-	-
May	1,072,127	76,743	-	-	-	1,148,870	1,993,041	76,743	-	-
June	1,148,870	76,743	-	-	-	1,225,613	2,069,784	76,743	-	-
July	1,225,613	76,743	-	-	-	1,302,356	2,146,527	76,743	-	-
August	1,302,356	76,743	-	-	-	1,379,099	2,223,270	76,743	-	-
September	1,379,099	76,743	-	-	-	1,455,842	2,300,013	76,743	-	-
October	1,455,842	76,743	-	-	-	1,532,584	2,376,755	76,743	-	-
November	1,532,584	76,743	-	-	-	1,609,327	2,453,498	76,743	-	-
December	1,609,327	76,743	-	-	-	1,686,070	2,530,241	76,743	-	-

Note A: Monthly cost estimated based on Company requested amount divided by 12 and ending on October 31, 2008, or the month that new rates become effective.

[1] Current \$0.00072 Recovery Rate through April. Effective May 1, 2008, Recovery Rate \$0.00294.

[2] Actual January 2008 cost, write-off and recovery amounts.

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-18
DOT PIPELINE SAFETY SURCHARGE CALCULATION**

**RECOVERY OF ACCOUNT 182.3 BALANCE @ APRIL 30, 2008 PLUS
50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATE EFFECTIVE MAY 1, 2008**

Line No.	Calendar Year (a)	Annual Estimates [1] (b)	Monthly Estimates (c) (b) / 12	Disallowed (c)	Recoverable (d)	Projected Therm Sales [2] (e)	Calculated Per Therm Surcharge (f)	Line No.
1	2008	920,914	76,743					1
2	2009	920,914	76,743					2
3	2010	920,914	76,743					3
4	2011	920,914	76,743					4
5	Apr 2008	1,375,007 [3]			1,375,007			5
6	May-Dec 2008	613,943 [4]	50%		306,971	392,332,760		6
7	Jan-Feb 2009	153,486 [5]	50%		76,743	206,844,670		7
10	Total				\$ 1,758,722	598,977,430 \$	0.00294	10
11					Average Annual Use Per Customer		332	11
12					Annual DOT Surcharge Per Customer \$		0.98	12
13					Monthly DOT Surcharge Per Customer \$		0.08	13

[1] Based on 2007 Actual Costs as Requested in Adj 9.

[2] Rate Case Volumes

[3] Balance @ April 30, 2008 (100%) Recoverable

[4] May through December Projected Volumes

[5] 2 Months Projected Volumes

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-18

TRIMP RECOVERY DOLLARS AND RATE PER THERM				
	Test Year	DOT	DOT	
	Rate Case	Rate	Recovery	
	Volumes			
January	108,927,515	\$ 0.00294	\$ 320,247	
February	97,717,155	0.00294	287,288	
March	83,220,367	0.00294	244,668	
April	60,913,121	0.00294	179,085	
May	49,936,376	0.00294	146,813	
June	41,594,843	0.00294	122,289	
July	38,828,036	0.00294	114,154	
August	36,646,593	0.00294	107,741	
September	38,153,138	0.00294	112,170	
October	41,933,546	0.00294	123,285	
November	54,244,256	0.00294	159,478	
December	90,995,972	0.00294	267,528	
	<u>743,110,918</u>	\$	<u>2,184,746</u>	

ATTACHMENT
STF-9-18

SOUTHWEST GAS CORPORATION
ARIZONA

DATA REQUEST NO. STF-9-18
TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TRIMP)

RECOVERY OF ACCOUNT 182.3 BALANCE @ APRIL 30, 2008 PLUS
50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE THROUGH OCTOBER 31, 2008
NEW RATE EFFECTIVE MAY 1, 2008, DEFERRAL OF COSTS TO CEASE ON NOVEMBER 1, 2008

Month	2004					2005				
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery
January	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ 414,227	\$ 3,288	\$ -	\$ -	\$ -
February	-	-	-	-	-	417,515	10,172	-	-	-
March	-	-	-	-	-	427,687	112,724	-	-	-
April	-	-	-	-	-	540,411	74,841	-	-	-
May	-	-	-	-	-	615,251	34,497	-	-	-
June	472	472	-	-	-	649,748	153,865	-	-	-
July	7,016	5,129	-	-	-	803,613	59,016	-	-	-
August	12,146	34,505	-	-	-	862,629	37,808	-	-	-
September	46,851	26,728	-	-	-	900,437	74,315	-	-	-
October	73,378	43,459	-	-	-	974,752	57,343	-	-	-
November	116,837	47,646	-	-	-	1,032,095	81,835	-	-	-
December	164,483	249,744	-	-	-	1,113,930	116,931	-	-	-

Month	2006					2007				
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery
January	\$ 1,230,860	\$ 3,399	\$ -	\$ -	\$ -	\$ 679,585	\$ 1,697	\$ (92,152)	\$ -	\$ (90,809)
February	1,234,260	112,185	-	-	-	498,320	89,940	(848)	-	(77,636)
March	1,346,445	89,028	(57,792)	(615,430)	(33,880)	509,778	51,725	(44,970)	-	(55,745)
April	728,371	14,518	(15,618)	-	(53,530)	460,787	295,845	(25,863)	-	(36,334)
May	673,741	78,761	(36,156)	-	(39,244)	694,435	219,061	(147,922)	-	(35,480)
June	677,103	25,789	(39,380)	-	(41,873)	730,094	563,459	(109,530)	-	(33,361)
July	621,648	11,717	(12,899)	-	(32,941)	1,150,862	161,870	(281,730)	-	(32,909)
August	587,524	25,739	(5,858)	-	(31,285)	997,893	382,430	(80,935)	-	(32,385)
September	576,119	61,416	(12,869)	-	(11,353)	1,267,003	606,096	(191,215)	-	(30,794)
October	613,312	40,780	(30,708)	-	(32,705)	1,651,090	211,300	(303,048)	-	(20,990)
November	590,690	53,182	(20,395)	-	(38,631)	1,538,352	145,226	(105,650)	-	(27,071)
December	584,845	184,305	(26,591)	-	(62,974)	1,550,858	17,513	(72,613)	-	(45,145)

[1] To write off 50% of 2004 & 2005 program costs incurred prior to implementing the deferred accounting and monthly surcharge in March 2006.

ATTACHMENT
STF-9-18

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-18
TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TRIMP)

RECOVERY OF ACCOUNT 182.3 BALANCE @ APRIL 30, 2008 PLUS
50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE THROUGH OCTOBER 31, 2008
NEW RATE EFFECTIVE MAY 1, 2008, DEFERRAL OF COSTS TO CEASE ON NOVEMBER 1, 2008

Month	2008						2009					
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00294 Recovery	Ending Balance	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00294 Recovery	Ending Balance
January [2]	\$ 1,450,612	\$ 63,984	\$ (8,756)	\$ -	\$ (78,193)	\$ 1,427,646	\$ 413,406	\$ -	\$ -	\$ -	\$ (320,247)	\$ 93,159
February	1,427,646	76,743	(31,992)	-	(70,356)	1,402,041	(194,129)	-	-	-	(267,285)	(194,129)
March	1,402,041	76,743	(38,371)	-	(59,919)	1,380,493	-	-	-	-	-	-
April	1,380,493	76,743	(38,371)	-	(43,857)	1,375,007	-	-	-	-	-	-
May	1,375,007	76,743	(38,371)	-	(146,813)	1,266,566	-	-	-	-	-	-
June	1,266,566	76,743	(38,371)	-	(122,289)	1,182,648	-	-	-	-	-	-
July	1,182,648	76,743	(38,371)	-	(114,154)	1,106,965	-	-	-	-	-	-
August	1,106,965	76,743	(38,371)	-	(107,741)	1,037,498	-	-	-	-	-	-
September	1,037,496	76,743	(38,371)	-	(112,170)	963,697	-	-	-	-	-	-
October	963,697	76,743	(38,371)	-	(123,285)	878,784	-	-	-	-	-	-
November	878,784	-	(38,371)	-	(159,478)	680,934	-	-	-	-	-	-
December	680,934	-	-	-	(267,528)	413,406	-	-	-	-	-	-

Month	2010						2011					
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00294 Recovery	Ending Balance	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00294 Recovery	Ending Balance
January	\$ -	\$ -	-	\$ -	-	-	\$ -	\$ -	-	\$ -	-	\$ -
February	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	-	-	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-
October	-	-	-	-	-	-	-	-	-	-	-	-
November	-	-	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-

Note A: Monthly cost estimated based on Company requested amount divided by 12 and ending on October 31, 2008, or the month that new rates become effective.
[1] Current \$0.00072 Recovery Rate through April. Effective May 1, 2008, Recovery Rate \$0.00294.
[2] Actual January 2008 cost, write-off and recovery amounts.

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-18
DOT PIPELINE SAFETY SURCHARGE CALCULATION**

**RECOVERY OF ACCOUNT 182.3 BALANCE @ APRIL 30, 2008 PLUS
50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATE EFFECTIVE MAY 1, 2008**

Line No.	Calendar Year (a)	Annual Estimates [1] (b)	Monthly Estimates (c) (b) / 12	Disallowed (c)	Recoverable (d)	Projected Therm Sales [2] (e)	Calculated Per Therm Surcharge (f)	Line No.
1	2008	920,914	76,743					1
2	2009	920,914	76,743					2
3	2010	920,914	76,743					3
4	2011	920,914	76,743					4
5	Apr 2008	1,375,007 [3]			1,375,007			5
6	May-Dec 2008	613,943 [4]	50%		306,971	392,332,760		6
7	Jan-Feb 2009	153,486 [5]	50%		76,743	206,644,670		7
10	Total				\$ 1,758,722	598,977,430	\$ 0.00294	10
11					Average Annual Use Per Customer		332	11
12					Annual DOT Surcharge Per Customer \$		0.98	12
13					Monthly DOT Surcharge Per Customer \$		0.08	13

[1] Based on 2007 Actual Costs as Requested in Adj 9.

[2] Rate Case Volumes

[3] Balance @ April 30, 2008 (100%) Recoverable

[4] May through December Projected Volumes

[5] 2 Months Projected Volumes

ATTACHMENT
STF-9-18

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-18**

TRIMP RECOVERY DOLLARS AND RATE PER THERM

Test Year	Rate Case	Volumes	DOT Rate	DOT Recovery
January	108,927,515	\$	0.00294	\$ 320,247
February	97,717,155		0.00294	287,288
March	83,220,367		0.00294	244,668
April	60,913,121		0.00294	179,085
May	49,936,376		0.00294	146,813
June	41,594,843		0.00294	122,289
July	38,828,036		0.00294	114,154
August	36,646,593		0.00294	107,741
September	38,153,138		0.00294	112,170
October	41,933,546		0.00294	123,285
November	54,244,256		0.00294	159,478
December	90,995,972		0.00294	267,528
	<u>743,110,918</u>			<u>\$ 2,184,746</u>

241-053

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-53:

Filing Information. As the Company discovers errors in its filing identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available.

Respondent: State Regulatory Affairs / Revenue Requirements

Response:

The following errors and corrections have been identified to date. Southwest will update this response if additional errors and/or corrections are identified.

1. Schedule C-2, Adjustment No. 12, Sheet 1, Line 6 has the incorrect number (it should not be the same number as Line 7). The correct number in column (c) should be \$5,507,176, and the adjustment allocated to Arizona in column (i) should be \$4,922. The revised sheet is attached and the changes are highlighted in bold. This change reduces the revenue requirement by \$23,447.

2. The second error relates to a \$300,000 credit that was booked into Account 923 instead of 925. On Schedule C-1, Sheet 9, Account 923 was increased by \$300,000 and Account 925 was decreased by \$300,000. This credit was related to self-insured retention. Therefore, Arizona direct self-insured retention on Schedule C-2, Adjustment No. 10, Line 13 was reduced by \$300,000. On Workpaper C-2, Adjustment No. 10, Sheet 73, Line 10(g) was also reduced by \$300,000. These revised sheets are attached and the changes are highlighted in bold. The net impact of this error increases the revenue requirement by \$284,514.

3. Southwest also corrected an error discovered on Schedule E-1, Sheet 2, Line 27. Total Company accumulated deferred income taxes at 4/30/07 and 12/31/06

(Continued on Page 2)

241-053
Page 2

Response to STF-1-53: (continued)

was correct, but the breakout between Arizona and Other ratemaking jurisdictions was not. A revised Schedule E-1 is attached. This error does not have an impact on the revenue requirement.

**SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
ADMINISTRATIVE AND GENERAL EXPENSES
ANNUALIZED PAIUTE ALLOCATION
ADJUSTMENT NO. 12**

Line No.	Description (a)	FERC Account Number (b)	12 Months Ended 04/30/07		Gross Recorded (e) (c) + (d)	MMF Allocation Paiute [3] (f)	Paiute Annualized (g)	Reduction to Paiute's A&G Expenses		Amount Allocated to Arizona [4] (i)	Line No.
			Net Recorded [1] (c)	Charged to Paiute [2] (d)				(h) (d) - (g)			
1	Administrative and General Salaries	920	\$ 56,785,724	\$ 2,402,071	\$ 59,187,796	3.92%	\$ 2,322,351	\$ 79,720	\$	45,201	1
2	Office Supplies	921	10,322,576	438,378	10,760,953	3.92%	422,227	16,150		9,157	2
3	Outside Services Employed	923	8,919,827	378,579	9,298,407	3.92%	364,842	13,738		7,789	3
4	Property Insurance	924	373,578	91,630	465,208	21.09%	98,118	(6,487)		(3,563)	4
5	Injuries and Damages	925	9,299,361	395,033	9,694,393	3.92%	380,379	14,654		8,309	5
6	Miscellaneous General Expenses	930.2	5,507,176	233,944	5,741,120	3.92%	225,264	8,680		4,922	6
7	Rents	931	4,453,278	190,026	4,643,304	3.92%	182,189	7,836		4,443	7
8	Maintenance of General Plant	935	1,833,689	77,859	1,911,548	3.92%	75,003	2,855		1,619	8
9	Total		\$ 97,495,209	\$ 4,207,520	\$ 101,702,729		\$ 4,070,374	\$ 137,146	\$	77,877	9

Explanation:

Consistent with the methodology accepted by the Commission in previous rate cases, this adjustment annualizes the recorded amounts allocated to Patute Pipeline to reflect Patute's MMF allocation percentage based on the test year ended April 30, 2007.

Note:

Account 493, Rent from Gas Property, changed by -\$63,304 due to annualizing the Paiute rental charge at April 30, 2007. Supporting Workpaper C-2, Adj. 12.

[1] Supporting Schedule C-1, Sh 9

[2] Source: Company Records

[3] Modified Massachusetts Formula as calculated in Sch C-1, Sh 18, Col (g): 21.09% based on insurable property. Supporting Worksheet C-2, Adj. 12.

[4] All accounts except 924 are allocated to Arizona using the 4-Factor. Account 924 uses the Factor II percentage. Supporting Schedule C-1, Sh 17.

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF RECORDED ADMINISTRATIVE AND GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Direct Charges			To Be Allocated (f) (c-d-e)	Allocation Factor (1)				Total Allocation (k)	Total (d) + (k)	Line No.
			Total Company (c)	Arizona (d)	Other Jurisdictions (e)		4-Factor (g)	Factor II (h)	Factor III (i)	A&G Allocation (j)			
1	Administrative and General Salaries	920	\$ 39,960,366	\$ 0	\$ 0	\$ 39,960,366	\$ 22,657,527	\$ 0	\$ 0	\$ 0	\$ 22,657,527	\$ 22,657,527	1
2	Labor		18,893,123	0	0	18,893,123	10,712,401	0	0	0	10,712,401	10,712,401	2
3	Labor Loadings		(2,067,764)	0	0	(2,067,764)	(1,172,422)	0	0	0	(1,172,422)	(1,172,422)	3
4	Materials and Expense		\$ 56,785,724	\$ 0	\$ 0	\$ 56,785,724	\$ 32,197,506	\$ 0	\$ 0	\$ 0	\$ 32,197,506	\$ 32,197,506	4
5	Office Supplies	921	\$ 10,322,576	\$ 0	\$ 0	\$ 10,322,576	\$ 5,852,900	\$ 0	\$ 0	\$ 0	\$ 5,852,900	\$ 5,852,900	5
6	Administrative Expenses Transferred - Credit	922	\$ (8,953,780)	\$ 0	\$ 0	\$ (8,953,780)	\$ 0	\$ 0	\$ 0	\$ (5,306,010)	\$ (5,306,010)	\$ (5,306,010)	6
7	Outside Services Employed	923	\$ 10,409,664	\$ 1,068,490	\$ 421,346	\$ 8,919,827	\$ 5,057,542	\$ 0	\$ 0	\$ 0	\$ 5,057,542	\$ 6,126,032	7
8	Property Insurance	924	\$ 373,578	\$ 0	\$ 0	\$ 373,578	\$ 0	\$ 205,169	\$ 0	\$ 0	\$ 205,169	\$ 205,169	8
9	Injuries and Damages	925	\$ 10,186,287	\$ 106,029	\$ 762,898	\$ 9,299,361	\$ 5,272,737	\$ 0	\$ 0	\$ 0	\$ 5,272,737	\$ 6,378,766	9
10	Employee Pensions and Benefits	926	\$ 0	\$ 179,818	\$ 32,821	\$ (212,639)	\$ 0	\$ 0	\$ (126,547)	\$ 0	\$ (126,547)	\$ 53,270	10
11	Regulatory Commission Expenses	928	\$ 349,604	\$ 125,693	\$ 223,911	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 125,693	11
12	Miscellaneous General Expenses	930	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	12
13	Labor		0	0	0	0	0	0	0	0	0	0	13
14	Labor Loadings		0	0	0	0	0	0	0	0	0	0	14
15	Materials and Expense		\$ 6,599,734	\$ 471,259	\$ 425,699	\$ 5,702,776	\$ 3,233,474	\$ 0	\$ 0	\$ 0	\$ 3,233,474	\$ 3,704,733	15
16	Total Miscellaneous General Expenses		\$ 6,599,734	\$ 471,259	\$ 425,699	\$ 5,702,776	\$ 3,233,474	\$ 0	\$ 0	\$ 0	\$ 3,233,474	\$ 3,704,733	16
17	Rent	931	\$ 4,453,278	\$ 0	\$ 0	\$ 4,453,278	\$ 2,525,009	\$ 0	\$ 0	\$ 0	\$ 2,525,009	\$ 2,525,009	17
18	Maintenance of General Plant	935	\$ 820,763	\$ 569,163	\$ 32,834	\$ 218,766	\$ 124,040	\$ 0	\$ 0	\$ 0	\$ 124,040	\$ 693,203	18
19	Labor		496,745	348,860	19,929	128,156	72,665	0	0	0	72,665	421,325	19
20	Labor Loadings		2,995,721	1,149,602	359,351	1,486,767	842,997	0	0	0	842,997	1,992,598	20
21	Materials and Expense		\$ 4,313,229	\$ 2,067,425	\$ 412,115	\$ 1,833,689	\$ 1,039,702	\$ 0	\$ 0	\$ 0	\$ 1,039,702	\$ 3,107,127	21
22	Total Maintenance of General Plant		\$ 4,313,229	\$ 2,067,425	\$ 412,115	\$ 1,833,689	\$ 1,039,702	\$ 0	\$ 0	\$ 0	\$ 1,039,702	\$ 3,107,127	22
23	Total Administrative and General Expenses		\$ 40,781,129	\$ 569,163	\$ 32,834	\$ 40,179,132	\$ 22,781,568	\$ 0	\$ 0	\$ 0	\$ 22,781,568	\$ 23,350,731	23
24	Labor		18,893,123	0	0	18,893,123	10,712,401	0	0	0	10,712,401	10,712,401	24
25	Labor Loadings		(2,067,764)	0	0	(2,067,764)	(1,172,422)	0	0	0	(1,172,422)	(1,172,422)	25
26	Materials and Expense		\$ 56,785,724	\$ 0	\$ 0	\$ 56,785,724	\$ 32,197,506	\$ 0	\$ 0	\$ 0	\$ 32,197,506	\$ 32,197,506	26
27	Total Administrative and General Expenses		\$ 94,821,894	\$ 4,018,714	\$ 2,278,790	\$ 88,524,381	\$ 55,178,870	\$ 205,169	\$ (126,547)	\$ (5,306,010)	\$ 48,951,482	\$ 53,970,196	27

(1) Schedule C-1, Sh 17

C-1, Sh 1

C-1, Sh 1

SOUTHWEST GAS CORPORATION
ARIZONA
DIRECT ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Labor/Loading Annualization Adj. No. 3 (c)	Rate Case Expense Adj. No. 13 (d)	Total Adjustments (e)	Line No.
1	Administrative and General Salaries	920				1
2	Labor		\$ 0 \$	0 \$	0	2
3	Labor Loadings		0	0	0	3
4	Materials and Expenses		0	0	0	4
	Total Administrative and General Salaries		0	0	0	
5	Office Supplies and Expense	921	\$ 0 \$	0 \$	0	5
6	Administrative Expenses Transferred - Credit	922	\$ 0 \$	0 \$	0	6
7	Outside Services Employed	923	\$ 0 \$	0 \$	0	7
8	Property Insurance	924	\$ 0 \$	0 \$	0	8
9	Injuries and Damages	925	\$ 0 \$	0 \$	0	9
10	Employee Pensions and Benefits	926	\$ 0 \$	0 \$	0	10
11	Regulatory Commission Expense	928	\$ 0 \$	(33,693) \$	(33,693)	11
12	Miscellaneous General Expense	930				12
13	Labor		\$ 0 \$	0 \$	0	13
14	Labor Loadings		0	0	0	14
15	Materials and Expenses		0	0	0	15
	Total Miscellaneous General Expense		0	0	0	
16	Rents	931	\$ 0 \$	0 \$	0	16
17	Maintenance of General Plant	935				17
18	Labor		\$ 28,359 \$	0 \$	28,359	18
19	Labor Loadings		(3,841)	0	(3,841)	19
20	Materials and Expenses		0	0	0	20
	Total Maintenance of General Plant		24,518	0	24,518	
21	Total Administrative and General					21
22	Labor		\$ 28,359 \$	0 \$	28,359	22
23	Labor Loadings		(3,841)	0	(3,841)	23
24	Materials and Expenses		0	(33,693)	(33,693)	24
	Total Administrative and General Expense		24,518	(33,693)	(9,175)	
					C-1, Sh 1	

SOUTHWEST GAS CORPORATION
ARIZONA
SYSTEM ALLOCABLE ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Labor/Loading Annualization Adj. No. 3 (c)	Miscellaneous Adjustments Adj. No. 5 (d)	Vehicle Compensation Adj. No. 6 (e)	Out-of-Period Expenses Adj. No. 7 (f)	Injuries and Damages Adj. No. 10 (g)	AGA Dues Adj. No. 11 (h)	Palute/SGTC Annualization Adj. No. 12 (i)	Total Adjustments (j)	Line No.
1	<u>Administrative and General Salaries</u>	920									1
2	Labor		\$ 1,167,758	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	1,167,758	2
3	Labor Loadings		10,876	0	0	0	0	0	0	10,876	3
4	Materials and Expenses		0	0	(251,850)	0	0	0	79,720	(172,130)	4
	Total Administrative and General Salaries		\$ 1,178,634	0 \$	(251,850) \$	0 \$	0 \$	0 \$	79,720 \$	1,006,503	
5	Office Supplies and Expense	921	\$ 0	(26,128) \$	0	0 \$	0 \$	0 \$	16,150 \$	(9,977)	5
6	Administrative Expenses Transferred - Credit	922	(158,561)	0 \$	0	0 \$	0 \$	0 \$	0 \$	(158,561)	6
7	Outside Services Employed	923	0	0 \$	0	0 \$	0 \$	0 \$	13,738 \$	13,738	7
8	Property Insurance	924	0	0 \$	0	0 \$	0 \$	0 \$	(6,487) \$	(6,487)	8
9	Injuries and Damages	925	0	0 \$	0	446,779 \$	4,430,545 \$	0 \$	14,654 \$	4,891,977	9
10	Employee Pensions and Benefits	926	0	0 \$	0	0 \$	0 \$	0 \$	0 \$	0	10
11	Regulatory Commission Expense	928	0	0 \$	0	0 \$	0 \$	0 \$	0 \$	0	11
	<u>Miscellaneous General Expense</u>	930									12
12	Labor		0	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	13
14	Materials and Expenses		0	(19,810)	0	0	0	(13,087)	8,680	(24,217)	14
15	Total Miscellaneous General Expense		\$ 0	(19,810) \$	0 \$	0 \$	0 \$	(13,087) \$	8,680 \$	(24,217)	15
16	Rents	931	0	0 \$	0	0 \$	0 \$	0 \$	7,836 \$	7,836	16
	<u>Maintenance of General Plant</u>	935									17
17	Labor		\$ 7,889	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	7,889	17
18	Labor Loadings		74	0	0	0	0	0	0	74	18
19	Materials and Expenses		0	0	0	0	0	0	2,855	2,855	19
20	Total Maintenance of General Plant		\$ 7,963	0 \$	0 \$	0 \$	0 \$	0 \$	2,855 \$	10,818	20
	<u>Total Administrative and General</u>										21
21	Labor		\$ 1,175,847	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	1,175,847	21
22	Labor Loadings		10,950	0	0	0	0	0	0	10,950	22
23	Materials and Expenses		(158,561)	(45,937)	(251,850)	446,779	4,430,545	(13,087)	137,146	4,545,034	23
24	Total Administrative and General Expense		\$ 1,028,035	(45,937) \$	(251,850) \$	446,779 \$	4,430,545 \$	(13,087) \$	137,146 \$	5,731,630	24

C-1, Sh 12

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADMINISTRATIVE AND GENERAL EXPENSE ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Total Company (c)	Direct Charges		To Be Allocated (f)	Allocation Factor (3)			Total Allocation (k)	Adjustment Total (l)
				Arizona (1) (d)	Other Jurisdictions (e)		Factor II (h)	Factor III (i)	Factor IV (j)		
			(d)+(e)+(f)								(d) + (k)
1	Administrative and General Salaries	920	\$ 1,167,758 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	662,119 \$
2	Labor		10,876	0	0	10,878	6,167	0	0	0	6,167
3	Labor Loadings		(172,130)	0	0	(172,130)	(97,598)	0	0	0	(97,598)
4	Materials and Expense		\$ 1,006,503 \$	0 \$	0 \$	1,008,503 \$	570,687 \$	0 \$	0 \$	0 \$	570,687 \$
5	Total Administrative and General Salaries										
6	Office Supplies	921	\$ (9,977) \$	0 \$	0 \$	(9,977) \$	(5,657) \$	0 \$	0 \$	0 \$	(5,657) \$
7	Administrative Expenses Transferred - Credit	922	\$ (158,561) \$	0 \$	0 \$	(158,561) \$	0 \$	0 \$	0 \$	(93,983) \$	(93,983) \$
8	Outside Services Employed	923	\$ 13,738 \$	0 \$	0 \$	13,738 \$	7,789 \$	0 \$	0 \$	0 \$	7,789 \$
9	Property Insurance	924	\$ (6,487) \$	0 \$	0 \$	(6,487) \$	0 \$	(3,563) \$	0 \$	0 \$	(3,563) \$
10	Injuries and Damages	925	\$ 4,891,977 \$	0 \$	0 \$	4,891,977 \$	2,773,751 \$	0 \$	0 \$	0 \$	2,773,751 \$
11	Employees Pensions and Benefits	926	\$ 0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$
12	Regulatory Commission Expenses	928	\$ (33,693) \$	(33,693) \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	(33,693) \$
13	Miscellaneous General Expenses	930	\$ 0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$	0 \$
14	Labor		0	0	0	0	0	0	0	0	0
15	Labor Loadings		(24,217)	0	0	(24,217)	(13,731)	0	0	0	(13,731)
16	Materials and Expense		\$ (24,217) \$	0 \$	0 \$	(24,217) \$	(13,731) \$	0 \$	0 \$	0 \$	(13,731) \$
17	Total Miscellaneous General Expenses										
18	Rents	931	\$ 7,836 \$	0 \$	0 \$	7,836 \$	4,443 \$	0 \$	0 \$	0 \$	4,443 \$
19	Maintenance of General Plant	935	\$ 36,248 \$	28,359 \$	0 \$	7,889 \$	4,473 \$	0 \$	0 \$	0 \$	4,473 \$
20	Labor		(3,767)	(3,841)	0	74	42	0	0	0	42
21	Labor Loadings		2,855	0	0	2,855	1,619	0	0	0	1,619
22	Materials and Expense		\$ 35,337 \$	24,518 \$	0 \$	10,818 \$	6,134 \$	0 \$	0 \$	0 \$	6,134 \$
23	Total Maintenance of General Plant										
24	Total Administrative and General Expenses		\$ 1,204,006 \$	28,359 \$	0 \$	1,175,647 \$	666,592 \$	0 \$	0 \$	0 \$	666,592 \$
25	Labor		7,109	(3,841)	0	10,950	6,208	0	0	0	6,208
26	Labor Loadings		(4,511,341)	(33,693)	0	4,545,034	2,670,817	(3,563)	0	(93,983)	2,573,091
27	Materials and Expense		\$ 5,722,456 \$	(9,175) \$	0 \$	5,731,630 \$	3,343,417 \$	(3,563) \$	0 \$	(93,983) \$	3,245,891 \$
28	Total Administrative and General Expenses										

[1] Schedule C-1, Sheet 10, Column e
[2] Schedule C-1, Sheet 11, Column j

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADJUSTED ADMINISTRATIVE AND GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Total Company (1) (c)	Direct Charges (2) (d)	Other Jurisdictions (3) (e)	To Be Allocated (f) (c-d-e)	4-Factor (g)	Factor II (h)	Allocation Factor (4) (i)	Total Allocation (k)	Total (l) (d) + (k)	Line No.
1	Administrative and General Salaries	920	\$ 41,128,124	\$ 0	\$ 0	\$ 41,128,124	\$ 23,319,646	\$ 0	\$ 0	\$ 23,319,646	\$ 23,319,646	1
2	Labor		18,903,999	0	0	18,903,999	10,718,567	0	0	10,718,567	10,718,567	2
3	Labor Loadings		(2,239,895)	0	0	(2,239,895)	(1,270,020)	0	0	(1,270,020)	(1,270,020)	3
4	Materials and Expense		\$ 57,792,228	\$ 0	\$ 0	\$ 57,792,228	\$ 32,768,193	\$ 0	\$ 0	\$ 32,768,193	\$ 32,768,193	4
5	Total Administrative and General Salaries		\$ 10,312,598	\$ 0	\$ 0	\$ 10,312,598	\$ 5,847,243	\$ 0	\$ 0	\$ 5,847,243	\$ 5,847,243	5
6	Office Supplies	921	\$ 10,312,598	\$ 0	\$ 0	\$ 10,312,598	\$ 5,847,243	\$ 0	\$ 0	\$ 5,847,243	\$ 5,847,243	6
7	Administrative Expenses Transferred - Credit	922	\$ (9,112,341)	\$ 0	\$ 0	\$ (9,112,341)	\$ 0	\$ 0	\$ 0	\$ (5,399,973)	\$ (5,399,973)	7
8	Outside Services Employed	923	\$ 10,423,402	\$ 1,068,490	\$ 421,346	\$ 8,933,565	\$ 5,065,331	\$ 0	\$ 0	\$ 5,065,331	\$ 6,133,821	8
9	Property Insurance	924	\$ 367,090	\$ 0	\$ 0	\$ 367,090	\$ 0	\$ 201,606	\$ 0	\$ 201,606	\$ 201,606	9
10	Injuries and Damages	925	\$ 15,060,264	\$ 106,029	\$ 762,898	\$ 14,191,336	\$ 8,046,489	\$ 0	\$ 0	\$ 8,046,489	\$ 8,152,517	10
11	Employee Pensions and Benefits	926	\$ 0	\$ 179,818	\$ 32,821	\$ (212,639)	\$ 0	\$ 0	\$ (126,547)	\$ 0	\$ (126,547)	11
12	Regulatory Commission Expenses	928	\$ 315,911	\$ 92,000	\$ 223,911	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	12
13	Miscellaneous General Expenses	930	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	13
14	Labor		\$ 6,575,517	\$ 471,259	\$ 425,699	\$ 5,678,560	\$ 3,219,743	\$ 0	\$ 0	\$ 3,219,743	\$ 3,691,002	14
15	Labor Loadings		\$ 6,575,517	\$ 471,259	\$ 425,699	\$ 5,678,560	\$ 3,219,743	\$ 0	\$ 0	\$ 3,219,743	\$ 3,691,002	15
16	Materials and Expense		\$ 4,461,114	\$ 0	\$ 0	\$ 4,461,114	\$ 2,529,452	\$ 0	\$ 0	\$ 2,529,452	\$ 2,529,452	16
17	Total Miscellaneous General Expenses		\$ 857,011	\$ 597,522	\$ 32,834	\$ 226,655	\$ 128,513	\$ 0	\$ 0	\$ 128,513	\$ 726,035	17
18	Maintenance of General Plant	935	\$ 482,978	\$ 344,820	\$ 19,929	\$ 128,230	\$ 72,706	\$ 0	\$ 0	\$ 72,706	\$ 417,526	18
19	Labor Loadings		\$ 2,898,576	\$ 1,149,602	\$ 399,351	\$ 1,489,622	\$ 844,616	\$ 0	\$ 0	\$ 844,616	\$ 1,994,218	19
20	Materials and Expense		\$ 4,348,565	\$ 2,091,943	\$ 412,115	\$ 1,844,507	\$ 1,045,836	\$ 0	\$ 0	\$ 1,045,836	\$ 3,137,779	20
21	Total Maintenance of General Plant		\$ 41,985,135	\$ 597,522	\$ 32,834	\$ 41,354,778	\$ 23,448,159	\$ 0	\$ 0	\$ 23,448,159	\$ 24,045,881	21
22	Administrative and General Expenses		\$ 19,396,977	\$ 344,820	\$ 19,929	\$ 19,032,229	\$ 10,791,274	\$ 0	\$ 0	\$ 10,791,274	\$ 11,136,093	22
23	Labor Loadings		\$ 39,182,238	\$ 3,087,198	\$ 2,226,027	\$ 33,869,014	\$ 24,282,853	\$ 201,606	\$ (126,547)	\$ 18,957,939	\$ 22,025,136	23
24	Materials and Expense		\$ 100,544,350	\$ 4,009,539	\$ 2,278,790	\$ 94,256,021	\$ 58,522,286	\$ 201,606	\$ (126,547)	\$ 53,197,372	\$ 57,209,911	24
	Total Administrative and General Expenses											

(1) Schedule C-1, Sheet 9, Column (c) + Schedule C-1, Sheet 12, Column (c)
(2) Schedule C-1, Sheet 9, Column (d) + Schedule C-1, Sheet 12, Column (d)
(3) Schedule C-1, Sheet 9, Column (e) + Schedule C-1, Sheet 12, Column (e)
(4) Schedule C-1, Sheet 17

SOUTHWEST GAS CORPORATION
ARIZONA
INJURIES AND DAMAGES
SELF-INSURED RETENTION NORMALIZATION
ADJUSTMENT NO. 10

Line No.	Description [1] (a)	Reference (b)	Allocation Percent (c)	System Allocable (d)	10-Year Total (e)	Total Arizona Accrual (f)	Line No.
	<u>Claims Paid</u>	WP C-2, Adj. 10					
1	< \$1,000,000				\$ 7,398,138		1
2	At \$1,000,000				8,000,000		2
3	\$1,000,000 < \$10,000,000				16,963,879		3
4	Total Claims Paid				\$ 32,362,017		4
5	10 Year Average					\$ 3,236,202	5
6	Less FERC Allocation @ 3.96%	C-1, Sh 18	3.96%			(128,154)	6
7	Net System Allocable					\$ 3,108,048	7
8	Arizona 4-Factor	C-1, Sh 17	56.70%			\$ 1,762,263	8
9	Recorded Amounts [2]			\$ 200,000			9
10	Less FERC Allocation @ 3.96%	C-1, Sh 18	3.96%	(7,920)			10
11	Net System Allocable			\$ 192,080			11
12	Arizona 4-Factor	C-1, Sh 17	56.70%			\$ 108,909	
13	Arizona Direct [2]		100.00%			(858,765)	
14	Total Recorded Arizona					\$ (749,856)	14
15	Total Adjustment (Ln 8 - Ln 14)					\$ 2,512,119	15

[1] Supporting Workpapers C-2, Adj. 10
[2] Source: Company Records

**SOUTHWEST GAS CORPORATION
ARIZONA
TEN YEAR HISTORY OF LIABILITY CLAIMS
FOR AMOUNTS LESS THAN ONE MILLION AND FIVE MILLION AGGREGATE PER YEAR**

Line No.	Year (a)	Paiute (b)	So. Ca. (c)	No. Ca. (d)	So. Nv. (e)	No. Nv. (f)	Arizona (g)	Sys Alloc. (h)	Total (i)	Line No.
Less Than \$1,000,000 Self-Insurance Per Claim										
1	1997						450,384		450,384	1
2	1998						1,494,253	123,755	1,618,008	2
3	1999			6,250	256,333		37,545		300,128	3
4	2000			18,125	208,216	195,000			421,341	4
5	2001		100,000		415,093		609,455		1,124,548	5
6	2002						400,000		400,000	6
7	2003		50,000		31,000		95,491		176,491	7
8	2004				92,500		560,500		653,000	8
9	2005		27,500		342,000		179,500	17,500	566,500	9
10	2006						1,553,678		1,553,678	10
11	2007				5,001		129,059		134,060	11
12		\$ 0	\$ 177,500	\$ 24,375	\$ 1,350,143	\$ 195,000	\$ 5,509,865	\$ 141,255	\$ 7,398,138	12
\$1,000,000 Self-Insurance Per Claim										
13	1997						1,000,000		1,000,000	13
14	1998					1,000,000	2,000,000		3,000,000	14
15	1999								0	15
16	2000					1,000,000			1,000,000	16
17	2001								0	17
18	2002								0	18
19	2003						1,000,000		1,000,000	19
20	2004						0		0	20
21	2005				1,000,000		1,000,000		2,000,000	21
22	2006								0	22
23	2007								0	23
24		\$ 0	\$ 0	\$ 0	\$ 1,000,000	\$ 2,000,000	\$ 5,000,000	\$ 0	\$ 8,000,000	24
\$5 Million Aggregate above \$1,000,000 Self-Insurance Per Claim										
25	1997						2,726,235		2,726,235	25
26	1998					6,272	1,739,870		1,746,142	26
27	1999								0	27
28	2000					991,502			991,502	28
29	2001								0	29
30	2002								0	30
31	2003						5,000,000		5,000,000	31
32	2004						1,500,000		1,500,000	32
33	2005						5,000,000		5,000,000	33
34	2006								0	34
35	2007								0	35
36		\$ 0	\$ 0	\$ 0	\$ 0	\$ 997,774	\$ 15,966,105	\$ 0	\$ 16,963,879	36
37	Total	\$ 0	\$ 177,500	\$ 24,375	\$ 2,350,143	\$ 3,192,774	\$ 26,475,970	\$ 141,255	\$ 32,362,017	

[1] Amounts for 1997 (May-December) and 2007 (January-April) are a partial year; 1998 through 2006 are based on calendar year amounts.

**SOUTHWEST GAS CORPORATION
COMPARATIVE BALANCE SHEETS**

Line No.	Description (a)	Balance at 4/30/07		Balance at 12/31/08		Balance at 12/31/09		Line No.
		Arizona (b)	Other (c)	Total (d)	Arizona (e)	Other (f)	Total (g)	
	Assets and Other Debits							
	Utility Plant							
1	Utility Plant (101, 105, 114, 118)	\$ 1,955,564,837	\$ 1,755,558,061	\$ 3,711,122,898	\$ 1,881,283,726	\$ 1,713,418,973	\$ 3,594,702,699	1
2	Construction Work in Progress (107)	11,303,613	38,662,860	49,966,593	30,910,335	43,313,114	74,223,449	2
3	Total Utility Plant	\$ 1,966,868,450	\$ 1,794,221,041	\$ 3,761,089,491	\$ 1,912,194,061	\$ 1,756,732,087	\$ 3,668,926,148	3
	Less: Accumulated Provision for Depreciation							
4	and Amortization (108, 111, 119)	688,698,589	582,306,358	1,271,004,927	674,414,547	580,886,077	1,255,300,624	4
5	Net Utility Plant	\$ 1,278,169,861	\$ 1,211,914,683	\$ 2,490,084,564	\$ 1,237,779,514	\$ 1,175,846,010	\$ 2,433,625,524	5
	Other Property and Investments							
6	Northern California Surcharge (120)	\$ -	\$ 5,547,483	\$ 5,547,483	\$ -	\$ 5,859,991	\$ 5,859,991	6
7	Non-Utility Property (121)	-	80,017	80,017	-	80,017	80,017	7
8	Non-Utility Accumulated Depreciation (122)	-	-	-	-	-	-	8
	Investment in Subsidiary and Associated							
9	Companies (123, 123.1)	-	135,594,132	135,594,132	-	131,083,571	131,083,571	9
10	Other Investments (124)	-	-	-	-	-	-	10
11	Special Funds (125, 128)	-	55,174,633	55,174,633	-	52,888,271	52,888,271	11
12	Total Other Property and Investments	\$ -	\$ 190,768,765	\$ 190,768,765	\$ -	\$ 183,971,842	\$ 183,971,842	12
	Current and Accrued Assets							
13	Cash (131)	\$ -	\$ (28,287,866)	\$ (28,287,866)	\$ -	\$ (9,643,554)	\$ (9,643,554)	13
14	Working Funds (135)	-	1,108,034	1,108,034	-	947,094	947,094	14
15	Temporary Cash Investments (138)	-	1,980,928	1,980,928	-	8,470,545	8,470,545	15
	Notes and Accounts Receivables Less Accumulated							
16	Provision for Uncollectible Accounts (141 - 144)	7,297,701	127,184,206	134,481,907	14,498,307	171,781,870	186,280,177	16
17	Receivables from Associated Companies (145-148)	-	19,921,310	19,921,310	-	23,248,322	23,248,322	17
18	Materials and Supplies (151, 154, 155, 163)	12,900,762	9,981,939	22,882,701	13,255,070	10,247,461	23,502,531	18
19	Liquefied Natural Gas Stored (164.1, 164.2)	-	8,951,081	8,951,081	-	14,005,846	14,005,846	19
20	Prepayments (165)	-	5,941,216	5,941,216	-	9,658,139	9,658,139	20
21	Interest and Dividends Receivable (171)	-	-	-	-	-	-	21
22	Accrued Utility Revenue (173)	-	40,300,000	40,300,000	-	73,300,000	73,300,000	22
23	Miscellaneous Current and Accrued Assets (174)	-	(7,283,008)	(7,283,008)	-	3,300,749	3,300,749	23
24	Total Current and Accrued Assets	\$ 20,198,463	\$ 179,807,842	\$ 200,006,305	\$ 27,753,377	\$ 305,286,472	\$ 333,049,849	24
	Deferred Debits							
25	Unamortized Debt Discount and Expenses (181)	\$ -	\$ 18,877,479	\$ 18,877,479	\$ -	\$ 19,334,215	\$ 19,334,215	25
26	Other Regulatory Assets (182)	4,807,329	31,954,790	36,762,119	4,985,215	70,719,430	75,704,645	26
27	Preliminary Survey and Investigation Charges (183)	-	(741,889)	(741,889)	-	(141,888)	(141,888)	27
28	Clearing Accounts (184)	(146,740)	250,916	104,176	(98,085)	155,105	57,020	28
29	Miscellaneous Deferred Debits (186)	5,515,015	4,973,360	10,488,395	5,781,981	5,255,832	11,037,813	29
30	Research & Development (188)	-	17,448,167	17,448,167	-	223,938	223,938	30
31	Loss on Reacquired Debt (189)	-	-	-	-	17,676,072	17,676,072	31
32	Accumulated Deferred Income Taxes (190)	63,014,918	36,820,369	99,835,287	67,851,766	36,820,369	104,672,135	32
33	Unrecovered Purchased Gas Costs (191)	73,180,522	89,502,198	162,682,720	78,520,877	91,541,811	170,062,688	33
34	Total Deferred Debits	\$ 1,371,558,966	\$ 1,077,620,988	\$ 2,449,179,954	\$ 1,344,053,768	\$ 1,850,212,217	\$ 3,194,265,985	34
35	Total Assets and Other Debits	\$ 1,371,558,966	\$ 1,077,620,988	\$ 2,449,179,954	\$ 1,344,053,768	\$ 1,850,212,217	\$ 3,194,265,985	35

NOTE: The Arizona columns above reflect only those amounts separately identified in the Southwest Gas general ledger as pertaining solely to Arizona. Allocations are not included, thus the debits and credits in the Arizona columns do not balance. The financial statements appearing herein are unaudited, and were prepared solely for the purposes of complying with the filing requirements for this general rate case.

**SOUTHWEST GAS CORPORATION
COMPARATIVE BALANCE SHEETS**

Line No.	Description (a)	Balance at 4/30/07		Balance at 12/31/08		Balance at 12/31/05		Line No.
		Arizona (b)	Other (c)	Total (d)	Arizona (e)	Other (f)	Total (g)	
	Liabilities and Other Credits							
	Proprietary Capital							
1	Common Stock Issued (201)	\$ -	\$ 43,781,138	\$ 43,781,138	\$ -	\$ 43,400,187	\$ 43,400,187	1
2	Preferred Stock Issued (204)	-	-	-	-	-	-	2
3	Premium on Capital Stock (207)	-	-	-	-	-	-	3
4	Other Paid in Capital (208-211)	-	719,685,842	719,685,842	-	708,785,500	708,785,500	4
5	Reacquired Capital Stock (217)	-	-	-	-	-	-	5
6	Capital Stock Expense (214)	-	(10,537,842)	(10,537,842)	-	(10,537,842)	(10,537,842)	6
7	Retained Earnings (216)	-	217,458,334	217,458,334	-	173,433,242	173,433,242	7
8	Total Proprietary Capital	\$ -	\$ 970,385,472	\$ 970,385,472	\$ -	\$ 915,091,067	\$ 915,091,067	8
	Long-Term Debt							
9	Bonds (221, 222)	\$ -	\$ 1,148,000,000	\$ 1,148,000,000	\$ -	\$ 1,148,000,000	\$ 1,148,000,000	9
10	Other Long-Term Debt (224, 226)	-	45,537,442	45,537,442	-	138,281,898	138,281,898	10
11	Other - Preferred Securities (224-1)	-	100,000,000	100,000,000	-	100,000,000	100,000,000	11
12	Total Long-Term Debt	\$ -	\$ 1,293,537,442	\$ 1,293,537,442	\$ -	\$ 1,386,281,898	\$ 1,386,281,898	12
	Current and Accrued Liabilities							
13	Notes Payable (231)	\$ -	\$ 95,913,923	\$ 95,913,923	\$ -	\$ 239,350,227	\$ 239,350,227	13
14	Accounts Payable (232)	-	7,190,228	7,190,228	-	7,644,900	7,644,900	14
15	Payables to Associated Companies (233, 234)	-	-	-	-	-	-	15
16	Customer Deposits (235)	34,911,701	32,449,462	67,361,163	32,944,984	31,205,607	64,150,601	16
17	Taxes Accrued (236)	13,259,372	45,344,420	58,603,792	12,379,928	7,155,100	19,535,028	17
18	Interest Accrued (237)	1,050,806	19,145,588	20,196,394	981,887	20,380,198	21,361,885	18
19	Dividends Declared (238)	-	9,062,521	9,062,521	-	8,582,910	8,582,910	19
20	Tax Collections Payable (241)	11,488,784	8,711,728	20,196,492	12,711,816	14,536,249	27,248,065	20
21	Miscellaneous Current and Accrued Liabilities (242)	6,223,324	53,752,965	59,976,289	3,027,404	51,709,315	54,736,719	21
22	Total Current and Accrued Liabilities	\$ 66,931,987	\$ 271,570,835	\$ 338,502,802	\$ 62,045,829	\$ 380,544,506	\$ 442,590,335	22
	Deferred Credits							
23	Customer Advances for Construction (252)	\$ 49,277,781	\$ 22,242,084	\$ 71,519,865	\$ 41,078,966	\$ 20,741,181	\$ 61,820,127	23
24	Other Deferred Credits (253)	26,392	36,940,811	36,967,003	26,392	35,738,640	35,765,032	24
25	Other Regulatory Liabilities (254)	13,778	7,066,731	7,070,509	15,500	7,256,393	7,271,893	25
26	Accumulated Deferred Investment Tax Credit (255)	6,251,910	3,789,207	10,041,117	6,428,030	3,902,279	10,330,309	26
27	Accumulated Deferred Income Taxes (282, 283)	185,959,471	135,219,302	321,178,773	194,324,404	140,939,000	335,263,404	27
28	Total Deferred Credits	\$ 241,529,332	\$ 205,247,935	\$ 446,777,267	\$ 241,873,292	\$ 208,576,463	\$ 450,451,755	28
	Other Long-Term Liabilities							
29	Injuries and Damages Reserve (228)	\$ -	\$ 1,976,871	\$ 1,976,871	\$ -	\$ 1,850,930	\$ 1,850,930	29
30	Provision for Rate Refunds (229)	-	-	-	-	-	-	30
31	Total Other Long-Term Liabilities	\$ -	\$ 1,976,871	\$ 1,976,871	\$ -	\$ 1,850,930	\$ 1,850,930	31
32	Total Liabilities and Other Credits	\$ 308,461,299	\$ 2,740,718,555	\$ 3,049,179,854	\$ 303,919,121	\$ 2,890,348,864	\$ 3,184,265,985	32

NOTE: The Arizona columns above reflect only those amounts separately identified in the Southwest Gas general ledger as pertaining solely to Arizona. Allocations are not included, thus the debits and credits in the Arizona columns do not balance. The financial statements appearing herein are unaudited, and were prepared solely for the purposes of complying with the filing requirements for this general rate case.

295-001

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-10
(ACC-STF-10-1 THROUGH ACC-STF-10-26)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 29, 2008

Request No. ACC-STF-10-1:

Expense for El Paso Natural Gas case. (a) Please identify by account all amounts of expense related to Southwest's participation in EPNG rate cases, by year for each 12 month period: 2004, 2005, 2006, 2007 and the 12 months ending April 30, 2007. (b) Please show how much of the amounts identified in response to part a were charged to Arizona operations, by account. (c) Please provide Southwest's budget for EPNG rate case participation for 2006, 2007 and 2008.

Respondent: Revenue Requirements

Response:

All amounts related to expenses for the El Paso Natural Gas rate case are in FERC account 923. Southwest does not budget legal fees or consultant/witness fees specifically for any single proceeding. An overall amount for outside legal and consulting costs is budgeted for the year without being specifically identified for any particular event. El Paso will be filing another rate case later in 2008, and Southwest expects to incur expenses related to its participation in that proceeding.

The attached worksheet shows the amounts for each historical 12-month period requested above and the amounts that would be allocated to Arizona.

SOUTHWEST GAS CORPORATION
ARIZONA
EPNG RATE CASE-RELATED LEGAL AND CONSULTANT COSTS
IN RESPONSE TO STF-10-1

<u>Twelve Months Ended</u>	<u>Account 923</u>		<u>Allocable to</u>	<u>Total</u>
	<u>Total</u>	<u>System</u>		
(a)	<u>Arizona</u>	<u>Allocable</u>	<u>Arizona [1]</u>	<u>Arizona</u>
	(b)	(c)	(d)	(e)
				(b) + (d)
12/31/04	\$ -	\$ -	\$ -	-
12/31/05	117,761	37,438	20,386	138,147
12/31/06	800,809	47,363	25,791	826,600
12/31/07	167,675	-	-	167,675
4/30/07	843,038	21,763	11,851	854,889

[1] Net of MMF, and 4-Factor Allocation:

MMF	3.96%
4-Factor to Arizona	56.70%

241-025

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-25:

Accumulated Deferred Income Taxes. Please provide a detailed itemization of each item of Accumulated Deferred Income Taxes as of 12/31/05 and 12/31/06. For each item, identify the book/tax-timing difference that causes the ADIT, explain when that temporary timing difference first arose, identify the amount of the timing difference as of each date, and describe in detail whether and how that particular timing difference relates to an item of utility rate base, utility revenue and/or utility expense, and how the related item has been reflected in the Company's filing for ratemaking purposes.

Respondent: Tax

Response:

Please see the attached spreadsheet with 12/31/05 and 12/31/06 Arizona and Common (system allocable) federal tax accumulated deferred income taxes.

**ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO
SOUTHWEST GAS CORPORATION
DOCKET NO. G-10551A-07-0504
RESPONSE TO STF 1.25**

DESCRIPTION	JURISDICTION	CUMULATIVE TEMPORARY DIFFERENCE BALANCE AT 12/31/05	TAX RATE	FEDERAL DEFERRED TAX LIABILITY (ASSET) BALANCE AT 12/31/05
PLANT				
GAS PLANT IN SERVICE	ARIZONA	148,173,877	34.40%	50,965,318
ACCUMULATED PROVISION FOR DEPRECIATION	ARIZONA	314,516,295	34.40%	108,179,817
CUSTOMER ADVANCES	ARIZONA	(19,585,777)	34.40%	(6,736,649)
GROSS-UP OF ADVANCES	ARIZONA	(26,392)	34.40%	(9,078)
GROSS-UP OF CIAC	ARIZONA	(18,944)	34.40%	(6,516)
NOL CARRYOVER	ARIZONA	(77,870,754)	35.00%	(27,254,764)
TOTAL		<u>365,188,305</u>		<u>125,138,128</u>
				Acct. 2820 2105
NON-PLANT 283.0				
ASSETS DEPRECIATED FOR TAX / NOT FOR BOOK	ARIZONA	7	35.00%	2
BAD DEBT	ARIZONA	(1,155,062)	35.00%	(404,272)
PBOP COSTS	ARIZONA	2,872,849	35.00%	1,005,497
TRANSMISSION INTEGRITY MGMT PROG - CEAZ	ARIZONA	291,401	35.00%	101,990
DEFERRED INVEST.	ARIZONA	382,843	35.00%	133,995
RATE CASE - ARIZONA - 2005	ARIZONA	54,541	35.00%	19,089
AZ LOW INCOME PROGRAM (LIRA)	ARIZONA	1,595,391	35.00%	558,387
TRANSMISSION INTEGRITY MGMT PROG - SAZ	ARIZONA	122,826	35.00%	42,989
ARIZONA CONSERVATION	ARIZONA	(338,687)	35.00%	(118,540)
CLEARING ACCOUNTS	ARIZONA	120,662	35.00%	42,232
CLEARING ACCOUNTS	ARIZONA	106,889	35.00%	37,411
MISCELLANEOUS DEFERRED DEBITS	ARIZONA	489,250	35.00%	171,238
ACCRUED LABOR	ARIZONA	309,344	35.00%	108,270
LIGHT RAIL PROJECT	ARIZONA	1,041,417	35.00%	364,496
PURCHASE GAS ADJUSTMENT	ARIZONA	97,691,704	35.00%	34,192,096
ACCUM PROV FOR INJURIES & DAMAGES - LITIGATION RESERVE	ARIZONA	(2,896,759)	35.00%	(1,013,866)
PROPERTY TAXES	ARIZONA	44,406	35.00%	15,542
ENERGY SHARE - FUEL FUND PROJECT	ARIZONA	(5,357)	35.00%	(1,875)
SECTION 263A INVENTORY, GAIN, CAP INT ADJUSTMENT	ARIZONA	(322,576)	35.00%	(112,902)
TOTAL		<u>100,405,089</u>		<u>35,141,781</u>
				Acct. 2830 2100

**ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO
SOUTHWEST GAS CORPORATION
DOCKET NO. G-10551A-07-0504
RESPONSE TO STF 1.25**

DESCRIPTION	JURISDICTION	CUMULATIVE TEMPORARY DIFFERENCE BALANCE AT 12/31/06	TAX RATE	DEFERRED TAX LIABILITY (ASSET) BALANCE AT 12/31/06
PLANT				
GAS PLANT IN SERVICE	ARIZONA	110,795,374	34.43%	38,143,286
ACCUMULATED PROVISION FOR DEPRECIATION	ARIZONA	348,668,576	34.43%	120,035,384
CUSTOMER ADVANCES	ARIZONA	(41,078,966)	34.43%	(14,142,168)
GROSS-UP OF ADVANCES	ARIZONA	(26,392)	34.43%	(9,086)
GROSS-UP OF CIAC	ARIZONA	(17,222)	34.43%	(5,929)
TOTAL		<u>418,341,370</u>		<u>144,021,487</u>
				Acct. 2820 2105
NON-PLANT 283.0				
BAD DEBT	ARIZONA	(1,116,265)	35.00%	(390,693)
PBOP COSTS	ARIZONA	2,535,325	35.00%	887,364
TRANSMISSION INTEGRITY MGMT PROG - CEAZ	ARIZONA	860,476	35.00%	301,167
RATE CASE - ARIZONA - 2005	ARIZONA	242,906	35.00%	85,017
AZ LOW INCOME PROGRAM (LIRA)	ARIZONA	2,365,052	35.00%	827,768
TRANSMISSION INTEGRITY MGMT PROG - SAZ	ARIZONA	370,384	35.00%	129,634
ARIZONA CONSERVATION	ARIZONA	(7,615)	35.00%	(2,665)
CLEARING ACCOUNTS	ARIZONA	(91,208)	35.00%	(31,923)
MISCELLANEOUS DEFERRED DEBITS	ARIZONA	489,250	35.00%	171,238
ACCRUED LABOR	ARIZONA	336,766	35.00%	117,868
PURCHASE GAS ADJUSTMENT	ARIZONA	90,602,669	35.00%	31,710,934
ACCUM PROV FOR INJURIES & DAMAGES - LITIGATION RESERVE	ARIZONA	(350,930)	35.00%	(122,826)
PROPERTY TAXES	ARIZONA	57,593	35.00%	20,158
ENERGY SHARE - FUEL FUND PROJECT	ARIZONA	(3,635)	35.00%	(1,272)
SECTION 263A INVENTORY, GAIN, CAP INT ADJUSTMENT	ARIZONA	(322,576)	35.00%	(112,902)
TOTAL		<u>95,968,192</u>		<u>33,588,867</u>
				Acct. 2830 2100

**ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO
SOUTHWEST GAS CORPORATION
DOCKET NO. G-10551A-07-0504
RESPONSE TO STF 1.25**

DESCRIPTION	JURISDICTION	CUMULATIVE TEMPORARY DIFFERENCE BALANCE AT 12/31/05	TAX RATE	FEDERAL DEFERRED TAX LIABILITY (ASSET) BALANCE AT 12/31/05
<u>PLANT</u>				
GAS PLANT IN SERVICE	COMMON	56,587,039	35.00%	19,805,464
ACCUMULATED PROVISION FOR DEPRECIATION	COMMON	(6,544,378)	35.00%	(2,290,532)
NOL CARRYOVER	COMMON	(10,535,303)	35.00%	(3,687,356)
TOTAL		<u>39,507,358</u>		<u>13,827,575</u>
				Acct. 2820 2105
<u>NON-PLANT 283.0</u>				
CAPITALIZED INTEREST IN CWIP	COMMON	7,368	35.00%	2,579
ASSETS DEPRECIATED FOR TAX / NOT FOR BOOK	COMMON	423	35.00%	148
BAD DEBT	COMMON	628,275	35.00%	219,896
PREPAYMENT	COMMON	774,308	35.00%	271,008
PBOP COSTS	COMMON	100,000	35.00%	35,000
DEFERRED INVEST.	COMMON	569,076	35.00%	199,176
RATE CASE - NEVADA 1999	COMMON	188,364	35.00%	65,928
CALIFORNIA PUBLIC PURPOSE PROGRAM	COMMON	70,646	35.00%	24,726
CLEARING ACCOUNTS	COMMON	69,017	35.00%	24,156
CLEARING ACCOUNTS	COMMON	35,440	35.00%	12,404
ACCRUED LABOR	COMMON	181,445	35.00%	63,506
UNAMORTIZED LOSS ON REACQUIRED DEBT	COMMON	15,452,802	35.00%	5,408,481
UNAMOR LOSS ON REACQ DEBT - PREF SECURITIES	COMMON	2,211,117	35.00%	773,891
INCENTIVE PAY	COMMON	(1,699,920)	35.00%	(594,972)
ACCUM PROV FOR INJURIES & DAMAGES - LITIGATION RESERVE	COMMON	(10,800,000)	35.00%	(3,780,000)
PENSION EXPENSE	COMMON	(1,805,881)	35.00%	(632,058)
ACCRUED VACATION PAY	COMMON	1,800,000	35.00%	630,000
INCENTIVE PAY	COMMON	490,554	35.00%	171,694
PBOP COSTS	COMMON	(4,123,934)	35.00%	(1,443,377)
SELF-INSURANCE/HEALTH DENTAL	COMMON	(2,198,353)	35.00%	(769,423)
ACCRUED PAST SERVICE LIABILITY (SERP)	COMMON	(19,686,368)	35.00%	(6,890,229)
OTHER DEFERRED CREDITS	COMMON	1,754,164	35.00%	613,957
DEFERRED COMPENSATION OFFICERS	COMMON	(12,782,994)	35.00%	(4,474,048)
DEFERRED COMPENSATION DIRECTORS	COMMON	(3,943,885)	35.00%	(1,380,360)
DEFERRED COMP INACTIVE OFFICERS	COMMON	(11,818,071)	35.00%	(4,136,325)
DEFERRED COMP INACTIVE DIRECTORS	COMMON	(2,601,873)	35.00%	(910,656)
CHARITABLE CONTRIBUTIONS	COMMON	(1,612,345)	35.00%	(564,321)

**SOUTHWEST GAS CORPORATION
DOCKET NO. G-10551A-07-0504
RESPONSE TO STF 1.25**

DESCRIPTION	JURISDICTION	CUMULATIVE TEMPORARY DIFFERENCE BALANCE AT 12/31/05	TAX RATE	FEDERAL DEFERRED TAX LIABILITY (ASSET) BALANCE AT 12/31/05
TOTAL		(48,740,625)		(17,059,219)

Acct. 2830 2100

**ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO
SOUTHWEST GAS CORPORATION
DOCKET NO. G-10551A-07-0504
RESPONSE TO STF 1.25**

DESCRIPTION	JURISDICTION	CUMULATIVE TEMPORARY DIFFERENCE BALANCE AT 12/31/06	TAX RATE	FEDERAL DEFERRED TAX LIABILITY (ASSET) BALANCE AT 12/31/06
PLANT				
GAS PLANT IN SERVICE	COMMON	59,832,131	35.00%	20,941,246
ACCUMULATED PROVISION FOR DEPRECIATION	COMMON	(12,409,511)	35.00%	(4,343,329)
TOTAL		47,422,620		16,597,917
				Acct. 2820 2105
NON-PLANT 283.0				
BAD DEBT	COMMON	726,207	35.00%	254,172
PREPAYMENT	COMMON	845,795	35.00%	296,028
TRANSMISSION INTEGRITY MGMT PROG - CEAZ	COMMON	(235,452)	35.00%	(82,408)
IDRB INTEREST RECOVERY	COMMON	1,045,838	35.00%	366,043
RATE CASE - ARIZONA - 2005	COMMON	44,794	35.00%	15,678
AZ LOW INCOME PROGRAM (LIRA)	COMMON	41,801	35.00%	14,630
CALIFORNIA PUBLIC PURPOSE PROGRAM	COMMON	100,524	35.00%	35,183
CALIFORNIA PUBLIC PURPOSE PROGRAM	COMMON	711,788	35.00%	249,126
TRANSMISSION INTEGRITY MGMT PROG - SAZ	COMMON	(315,823)	35.00%	(110,538)
CLEARING ACCOUNTS	COMMON	69,017	35.00%	24,156
CLEARING ACCOUNTS	COMMON	257,540	35.00%	90,139
MISCELLANEOUS DEFERRED DEBITS	COMMON	598,192	35.00%	209,367
ACCRUED LABOR	COMMON	205,230	35.00%	71,831
UNAMORTIZED LOSS ON REACQUIRED DEBT	COMMON	15,321,596	35.00%	5,362,559
UNAMOR LOSS ON REACQ DEBT - PREF SECURITIES	COMMON	2,202,691	35.00%	770,942
INCENTIVE PAY	COMMON	(1,093,752)	35.00%	(382,813)
ACCUM PROV FOR INJURIES & DAMAGES - LITIGATION RESERVE	COMMON	(1,000,000)	35.00%	(350,000)
PENSION EXPENSE	COMMON	(707,583)	35.00%	(247,654)
ACCRUED VACATION PAY	COMMON	1,660,000	35.00%	581,000
INCENTIVE PAY	COMMON	(3,780,636)	35.00%	(1,323,223)
PBOP COSTS	COMMON	(3,736,073)	35.00%	(1,307,626)
SELF-INSURANCE/HEALTH DENTAL	COMMON	(2,404,023)	35.00%	(841,408)
ACCRUED PAST SERVICE LIABILITY (SERP)	COMMON	(20,680,759)	35.00%	(7,238,266)
OTHER DEFERRED CREDITS	COMMON	2,654,639	35.00%	929,124
DEFERRED COMPENSATION OFFICERS	COMMON	(12,658,287)	35.00%	(4,430,401)
DEFERRED COMPENSATION DIRECTORS	COMMON	(3,027,404)	35.00%	(1,059,591)
DEFERRED COMP INACTIVE OFFICERS	COMMON	(12,949,653)	35.00%	(4,532,379)
DEFERRED COMP INACTIVE DIRECTORS	COMMON	(4,830,056)	35.00%	(1,690,520)
STOCK OPTIONS	COMMON	(580,757)	35.00%	(203,265)
TOTAL		(41,514,607)		(14,530,112)

SOUTHWEST GAS CORPORATION
DOCKET NO. G-10551A-07-0504
RESPONSE TO STF 1.25

DESCRIPTION	JURISDICTION	CUMULATIVE TEMPORARY DIFFERENCE BALANCE AT 12/31/06	TAX RATE	FEDERAL DEFERRED TAX LIABILITY (ASSET) BALANCE AT 12/31/06

Acct. 2830 2100

241-009

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

* * *

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-9:

M&S and Prepayments.

- a Please provide the monthly amounts of M&S for the 60 months ending September 30, 2007.
- b Please provide the monthly amounts of Prepayments for the 60 months ending September 30, 2007.

Please also provide the monthly amounts of Customer Deposits for the 60 months ending September 30, 2007.

Respondent: Revenue Requirements

Response:

Please find attached a schedule showing the monthly balances for M&S, Prepayments, and Customer Deposits for the period September 2002 through September 2007.

**SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMERS DEPOSITS
RESPONSE TO DATA REQUEST NO. STF-1-9
FOR THE PERIOD SEPTEMBER 2002 THROUGH SEPTEMBER 2007**

Description (a)	Customer Deposits		Line No.
	23500001 & 1320		
	AZ		
September 2002	\$	16,250,822	1
October		16,492,184	2
November		16,804,948	3
December		17,151,007	4
January 2003		17,539,415	5
February		17,955,206	6
March		18,771,907	7
April		19,779,385	8
May		20,563,887	9
June		21,068,603	10
July		21,361,867	11
August		21,697,818	12
September		22,116,629	13
October		22,421,280	14
November		22,915,023	15
December		23,429,731	16
January 2004		23,858,508	17
February		24,244,633	18
March		24,547,955	19
April		24,807,840	20
May		24,958,957	21
June		25,170,362	22
July		25,267,247	23
August		25,421,849	24
September		25,552,621	25
October		25,848,938	26
November		26,282,708	27
December		26,682,829	28
January 2005		27,087,182	29
February		27,467,386	30
March		27,823,958	31
April		27,893,262	32
May		28,063,139	33
June		28,169,344	34
July		28,186,789	35
August		28,307,776	36
September		28,394,707	37
October		28,538,698	38
November		28,856,769	39
December		29,139,638	40
January 2006		29,453,967	41
February		29,642,993	42
March		29,683,090	43

**SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMERS DEPOSITS
RESPONSE TO DATA REQUEST NO. STF-1-9
FOR THE PERIOD SEPTEMBER 2002 THROUGH SEPTEMBER 2007**

<u>Description</u> (a)	<u>Customer Deposits</u> <u>23500001 & 1320</u> <u>AZ</u>	<u>Line</u> <u>No.</u>
April	29,940,535	44
May	30,244,306	45
June	30,534,170	46
July	30,907,669	47
August	31,068,422	48
September	31,294,651	49
October	31,925,334	50
November	32,387,660	51
December	32,677,847	52
January 2007	32,866,855	53
February	33,171,595	54
March	33,562,862	55
April	34,402,771	56
May	34,944,231	57
June	35,653,565	58
July	36,066,017	59
August	36,447,849	60
September	36,827,715	61

**SOUTHWEST GAS CORPORATION
ARIZONA
PREPAYMENTS
RESPONSE TO DATA REQUEST NO. STF-1-9
FOR THE PERIOD SEPTEMBER 2002 THROUGH SEPTEMBER 2007**

Line No.	Description (a)	Balance [1] (b)	4-Factor (c)	Allocation (d)	Line No.
1	September 2002 \$	3,659,675			1
2	October	3,515,864			2
3	November	3,166,262			3
4	December	3,846,794			4
5	January 2003	4,265,975			5
6	February	4,125,358			6
7	March	3,662,244			7
8	April	4,060,414			8
9	May	3,626,974			9
10	June	2,795,477			10
11	July	5,057,769			11
12	August	5,130,082			12
13	September	4,798,680			13
14	October	3,784,576			14
15	November	3,956,561			15
16	December	5,938,689			16
17	January 2004	5,258,062			17
18	February	4,984,761			18
19	March	4,810,591			19
20	April	4,204,986			20
21	May	4,296,987			21
22	June	3,639,813			22
23	July	3,377,801			23
24	August	7,698,845			24
25	September	7,034,140			25
26	October	7,298,412			26
27	November	6,063,437			27
28	December	7,432,925			28
29	January 2005	6,723,166			29
30	February	6,476,582			30
31	March	5,712,733			31
32	April	5,268,333			32
33	May	4,602,628			33
34	June	3,555,579			34
35	July	2,750,681			35
36	August	9,249,020			36
37	September	8,486,989			37
38	October	7,955,446			38
39	November	7,793,183			39
40	December	9,066,598			40
41	January 2006	8,469,241			41
42	February	7,005,388			42
43	March	6,179,169			43
44	April	5,367,019			44
45	May	4,571,452			45
46	June	3,756,402			46

**SOUTHWEST GAS CORPORATION
ARIZONA
PREPAYMENTS
RESPONSE TO DATA REQUEST NO. STF-1-9
FOR THE PERIOD SEPTEMBER 2002 THROUGH SEPTEMBER 2007**

Line No.	Description (a)	Balance [1] (b)	4-Factor (c)	Allocation (d)	Line No.
47	July	5,219,958			47
48	August	9,299,535			48
49	September	8,623,454			49
50	October	7,836,438			50
51	November	6,430,014			51
52	December	9,144,710			52
53	January 2007	8,343,687			53
54	February	7,723,320			54
55	March	6,044,664			55
56	April	5,600,962			56
57	May	4,801,987			57
58	June	3,257,471			58
59	July	4,640,702			59
60	August	9,930,978			60
61	September	9,134,161			61

**SOUTHWEST GAS CORPORATION
ARIZONA
MATERIALS AND SUPPLIES INVENTORY
RESPONSE TO DATA REQUEST NO. STF-1-9
FOR THE PERIOD SEPTEMBER 2002 THROUGH SEPTEMBER 2007**

Line No.	Description (a)	Account 154 (b)	Account 155 (c)	Account 163 (d)	System Allocable (e)	Total M&S (f)	Line No.
1	September 2002	4,938,589	35,008	858,945	(11,447)	5,821,095	1
2	October	5,205,449	34,609	732,317	(11,461)	5,960,913	2
3	November	5,348,539	34,750	805,850	(11,849)	6,177,290	3
4	December	5,529,443	29,845	586,973	(12,007)	6,134,254	4
5	January 2003	6,474,637	26,964	508,851	(12,166)	6,998,287	5
6	February	6,890,699	37,309	419,468	(12,210)	7,335,266	6
7	March	6,677,835	42,393	225,777	(12,425)	6,933,580	7
8	April	6,681,758	39,398	377,088	(12,544)	7,085,700	8
9	May	6,775,201	39,319	558,830	(12,627)	7,360,722	9
10	June	6,450,145	34,293	653,058	(12,662)	7,124,833	10
11	July	6,628,801	34,278	725,420	(12,795)	7,375,705	11
12	August	6,911,999	31,835	790,866	(9,606)	7,725,095	12
13	September	7,626,204	31,565	807,234	(9,873)	8,455,130	13
14	October	7,828,138	34,790	927,229	(10,476)	8,779,680	14
15	November	8,249,076	35,065	742,627	(10,644)	9,016,124	15
16	December	8,114,240	31,523	475,427	(238)	8,620,952	16
17	January 2004	8,214,192	33,209	462,161	(10,499)	8,699,063	17
18	February	8,085,645	32,735	307,899	(10,973)	8,415,305	18
19	March	7,943,077	34,246	559,761	(11,080)	8,526,004	19
20	April	7,930,710	41,188	636,464	(11,317)	8,597,046	20
21	May	7,658,420	38,989	544,264	(11,416)	8,230,257	21
22	June	8,179,282	35,804	443,632	(11,411)	8,647,307	22
23	July	8,592,485	36,166	457,488	(11,131)	9,075,008	23
24	August	11,501,995	39,682	534,759	(11,648)	12,064,787	24
25	September	12,162,546	37,944	684,290	(13,671)	12,871,110	25
26	October	12,257,914	39,839	812,479	(14,530)	13,095,702	26
27	November	12,709,519	41,154	834,524	(14,653)	13,570,544	27
28	December	11,556,992	39,703	856,224	(15,213)	12,437,705	28
29	January 2005	11,254,858	43,639	674,339	(13,873)	11,958,963	29
30	February	10,862,993	40,357	657,333	(13,923)	11,546,760	30
31	March	10,188,488	31,318	726,376	(14,007)	10,932,175	31
32	April	11,781,705	37,198	785,667	(14,085)	12,590,485	32
33	May	12,604,617	35,520	1,078,638	(14,290)	13,704,485	33
34	June	12,925,175	35,483	651,422	(14,294)	13,597,786	34
35	July	12,505,803	35,189	521,864	(14,340)	13,048,516	35
36	August	12,778,545	31,593	472,835	(14,344)	13,268,630	36
37	September	12,219,677	32,796	665,858	(14,393)	12,903,939	37
38	October	11,935,240	32,855	655,846	(14,472)	12,609,469	38
39	November	11,341,564	27,272	552,237	(14,510)	11,906,563	39
40	December	10,808,705	28,337	651,384	(14,645)	11,473,781	40
41	January 2006	11,152,295	34,584	629,423	(14,841)	11,801,461	41
42	February	10,578,221	37,163	300,998	(14,894)	10,901,489	42
43	March	10,388,331	34,791	575,266	(14,904)	10,983,484	43
44	April	10,597,125	32,492	279,910	(15,105)	10,894,422	44
45	May	11,983,908	33,770	271,892	(15,266)	12,274,304	45
46	June	11,689,534	34,098	182,004	(15,364)	11,890,271	46
47	July	11,770,954	36,340	170,741	(15,553)	11,962,482	47
48	August	11,445,271	39,575	292,884	(15,638)	11,762,092	48
49	September	11,495,118	36,003	546,932	(15,730)	12,062,323	49
50	October	12,297,156	37,707	712,071	(15,751)	13,031,183	50
51	November	12,188,899	34,120	828,671	(13,992)	13,037,697	51
52	December	11,943,342	32,556	1,063,757	(14,070)	13,025,585	52
53	January 2007	11,734,137	33,185	914,604	(15,954)	12,665,971	53

**SOUTHWEST GAS CORPORATION
ARIZONA
MATERIALS AND SUPPLIES INVENTORY
RESPONSE TO DATA REQUEST NO. STF-1-9
FOR THE PERIOD SEPTEMBER 2002 THROUGH SEPTEMBER 2007**

Line No.	Description (a)	Account 154 (b)	Account 155 (c)	Account 163 (d)	System Allocable (e)	Total M&S (f)	Line No.
54	February	10,991,050	34,695	1,082,310	(16,072)	12,091,984	54
55	March	12,320,228	32,740	1,363,463	(16,207)	13,700,224	55
56	April	11,644,649	32,332	1,009,492	(16,343)	12,670,131	56
57	May	13,018,412	31,454	1,007,581	(16,452)	14,040,995	57
58	June	12,640,164	27,739	983,015	(16,666)	13,634,252	58
59	July	13,015,931	30,815	1,004,738	(16,948)	14,034,537	59
60	August	12,550,873	29,540	1,178,540	(17,002)	13,741,951	60
61	September	13,237,968	27,999	1,170,905	(17,106)	14,419,766	61

294-010

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-9
(ACC-STF-9-1 THROUGH ACC-STF-9-21)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 28, 2008

Request No. ACC-STF-9-10:

Incentive Programs. Refer to the response to STF-1-78, Attachment A. (a) Please explain fully and in detail whether the test year amounts shown for SWG's (1) Management Incentive Program (MIP), (2) Exempt Special Incentive, and (3) Service Planning Quality Incentive Award of \$7,416,322, \$96,925 and \$137,522, respectively, are the expense for Arizona operations. (b) If so, please provide a breakout of such amounts by each category referenced above, and show how the expense for Arizona operations was derived. Show detailed calculations, including total amounts, allocation factors used, and Arizona expense amounts. (c) Are there any System Allocable amounts related to these incentive programs? If so, please identify, quantify and explain the amounts. (d) Please confirm that the four-factor of 56.70% was applied by Southwest to the System Allocable amounts to derive the expense charged to Arizona and provide such amounts. If some other factor was used to allocate such amounts to Arizona, please show detailed calculations, and provide a complete explanation.

Respondent: Revenue Requirements

Response:

The MIP and Exempt Special Incentive amounts described in the Company's response to data request no. STF-1-78 are System Allocable amounts, before allocation to Arizona. All amounts under these two programs are charged to Account 920, which is a System Allocable account.

The Service Planning Quality Incentive Award amount in the AZ column of the Company's response to STF-1-78 is earned by Southwest employees in its Arizona divisions. These are direct charges to Arizona, and no allocations are involved. The amount in the CORP column is earned by Southwest employees based at its

(Continued on Page 2)

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Page 2

Response to ACC-STF-9-10: (continued)

corporate headquarters, and is automatically allocated to each ratemaking jurisdiction monthly by Southwest's general ledger (including Arizona) using Factor 4, number of customers.

The attached spreadsheet shows how the test year amounts are allocated to Arizona. Prior to using the 4-Factor to allocate the MIP and Special Incentive amounts to Arizona, the MMF is first applied to allocate a portion to the Company's FERC jurisdictional operations, as a portion of Corporate employees' time is spent supporting Paiute Pipeline and Southwest Gas Transmission Co. The MMF is not applied to the Quality Incentive Award amounts since these employees' functions do not support Southwest's pipeline subsidiaries, and the Corporate amounts are allocated using Factor 4 since these employees are in the Customer Accounts function (Account 903) and number of customers is a cost driver for this function.

**SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TEST YEAR ARIZONA INCENTIVE PROGRAM AMOUNTS
RESPONSE TO DATA REQUEST NO. STF-9-10**

	<u>CORP</u>	<u>AZ</u>	<u>TOTAL</u>	<u>NET OF MMF 3.96%</u>	<u>4-Factor 56.70%</u>	<u>TOTAL AZ</u>
MIP	\$ 7,416,322		\$ 7,416,322	\$ 7,122,636		\$ 4,038,534
Exempt Special Incentive	96,925	65,025	161,950	155,537		88,189
Service Planning Quality Incentive Award		290,004	==> Direct, no allocation			290,004
	137,522				<u>Factor 4 53.98%</u>	74,234

241-078

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-78:

Payroll, Incentive Programs. Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years. Identify all incentive and bonus program expense incurred in 2005, 2006 and 2007. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2005, 2006 and 2007.

Respondent: Human Resources / Revenue Requirements

Response:

The Management Incentive Plan and Special Incentive Plan are discussed in the Company's response to data request no. STF-1-49. The current document for the Service Planning Quality Incentive Award is attached as Attachment A. The expense incurred in 2005, 2006, and for the test year ended April 2007 for each program is attached as Attachment B. Please note the amounts shown for "Corporate" are before 4-Factor allocation to Arizona.

There are no incentive or bonus program expenses allocated from affiliates.

**SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
INCENTIVE PROGRAMS
IN RESPONSE TO DATA REQUEST NO. STF-1-78**

	DATE	CORP	AZ	Account
MIP				
	2005	\$ 5,668,050		920
	2006	6,728,050		920
	12ME Apr 07	7,416,322		920
Exempt Special Incentive				
	2005	\$ 121,450	\$ 40,500	920
	2006	89,000	72,950	920
	12ME Apr 07	96,925	65,025	920
Service Planning Quality Incentive Award				
	2005	\$ 140,171	\$ 465,150	903
	2006	143,865	367,534	903
	12ME Apr 07	137,522	290,004	903

STF-1-78
ATTACHMENT B



SOUTHWEST GAS

**SERVICE PLANNING
QUALITY INCENTIVE
AWARD**

2006



SOUTHWEST GAS

Service Planning Quality Incentive Award

**Service Planning Quality Incentive Award for 2006
Table of Contents**

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2006 Service Planning Award Processing Schedule.....	4
Service Planning Quality Incentive Award – 2006	5



1. Administrative Information

A. The effects of the Service Planning Quality Incentive Award on employee benefits are summarized below:

1. **Salary Continuation Program**

Coverage is provided at no cost to the employee. Payments are based on the hourly rate computed from an individual's September 1 base salary and the previous four quarters total Quality Incentive Award compensation.

2. **Retirement**

Quality Incentive Award compensation is included in the average effective earnings of the five highest calendar years of continuous service during the ten years immediately prior to termination.

3. **EIP**

EIP contributions are deducted from Quality Incentive Award payments, when paid, at the rate specified by the individual. Contributions are matched \$.50 on each \$1.00 contributed up to six percent (6%) of total annual earnings, subject to any IRS limitations.

4. **Life Insurance**

a) **Basic**

Salary utilized in the computation of life insurance entitlement is comprised of the individual's September 1 base salary and the previous four quarters total Quality Incentive Award compensation.

b) **Employee Custom Life Insurance**

Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).



c) Spouse Custom Life

Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

5. Accidental Death and Dismemberment Insurance

a) Basic

Salary utilized in the computation of life insurance entitlement is comprised of the individual's September 1 base salary and the previous four quarters total Quality Incentive Award compensation.

b) Additional

Amounts available for purchase are set for all employees (employee paid).

c) Business Travel Accidental Insurance

Coverage is equal to the individual's September 1 base salary and the previous four quarters total Quality Incentive Award compensation. The premium is entirely Company paid.

6. Long-term Disability

a) Basic (Option 1)

Coverage is provided at no cost to the employee. Payout is 50 percent of the individual's September 1 base salary and the monthly average of the previous four quarters total Quality Incentive Award compensation.

b) Additional (Option 2)

Coverage is employee paid. Payout is 16⅔ percent of the individual's September 1 base salary and the monthly average of the previous four quarters total Quality Incentive Award compensation. This brings total coverage to 66⅔ percent of the individual's September 1 base salary and the monthly average of



SOUTHWEST GAS

Service Planning Quality Incentive Award

the previous four quarters total Quality Incentive Award compensation.

- B. Termination of or adjustments to this Quality Incentive Award program could occur at any time at the discretion of the Company, as determined by executive management.



Service Planning Quality Incentive Award

**PROCESSING SCHEDULE
2006**

QUARTER	DUE TO ENERGY SERVICES	DUE TO PAYROLL	PAYDATE
4TH 2005*	01/18/06	01/20/06	01/26/06
1ST 2006	04/21/06	04/24/06	04/28/06
2ND 2006	07/20/06	07/21/06	07/27/06
3RD 2006	10/20/06	10/23/06	10/27/06

***Note: This will be the last payment based on the previous compensation plan. No payments will be carried over to the new plan.**



SOUTHWEST GAS

Service Planning Quality Incentive Award

Service Planning Quality Incentive Award 2006

The Service Planning Quality Incentive Award will be effective beginning January 1, 2006.

The Service Planning Quality Incentive Award will be based on the employee's outstanding achievement and performance for that quarter based on defined production criteria including, but not limited to, customer satisfaction, leadership, innovation and working within the allowable budget. The Quality Incentive Award value will be justified based on the defined criteria for the individual employee based on their service territory and submitted to the Division Vice President. Once approved by the Division Vice President, the values will be forwarded to the Energy Services Department for compilation and totaling with all divisions and forwarded to Payroll for processing.

The Service Planning Quality Incentive Award value will be up to a maximum of \$2500.00 per quarter per Service Planner or Senior Service Planner, up to a maximum of \$10,000 annually. A percentage of the award may be earned based on the measured results of the defined criteria.

The Service Planning Quality Incentive Award will be paid quarterly.

Note: The plan for 2005 is final as of December 31, 2005.

243-010

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**RESIDENTIAL UTILITY CONSUMER OFFICE
DATA REQUEST NO. RUCO-1
(RUCO-1-1 THROUGH RUCO-1-22)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 27, 2007

Request No. RUCO-1-10:

Employee Incentives

Please provide a description of each current employee incentive program. For each program offered, provide the following additional information:

- a) Employee eligibility;
- b) Cost incurred in each year 2004, 2005, 2006, and the test year; and
- c) The account where each expense identified in part b) was recorded.

Respondent: Human Resources

Response:

A description of each current employee incentive program was provided in the Company's response to data request nos. STF-1-49 and STF-1-78, provided in response to data request no. RUCO-1-6.

Please see the attached schedule for the information requested in parts a) through c). Please note that amounts shown for "Corporate" are before 4-Factor allocation to Arizona.

**SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
INCENTIVE PROGRAMS
RESPONSE TO DATA REQUEST NO. RUCO-1-10**

	DATE	CORP	AZ	Account
MIP				
(actual amounts rec'd in	2004	\$ 5,727,800		
January of calendar year)	2005	5,668,050		920
Eligibility: Sr Mgrs and Above	2006	6,728,050		920
	12ME Apr 07	7,416,322		920
Exempt Special Incentive				
Eligibility: All non-incentive	2004	\$ 84,200	\$ 38,000	920
exempts with at least 6	2005	121,450	40,500	920
mos. service	2006	89,000	72,950	920
	12ME Apr 07	96,925	65,025	920
Service Planning				
Quality Incentive Award	2004	\$ 168,035	\$ 431,425	903
Eligibility: service planners,	2005	140,171	465,150	903
their supvs and managers,	2006	143,865	367,534	903
industrial gas engineers	12ME Apr 07	137,522	290,004	903

254-041

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-41:

Please identify the total number of Southwest Gas employees who were eligible for SERP in each year, 2003 through 2007, and the total amount of SERP each year.

- a. Also indicate the total amount of SERP expense charged to Southwest Gas's Arizona ACC-jurisdictional operations in each year.

Respondent: Revenue Requirements/Human Resources

Response: **SUPPLEMENTAL ATTACHMENT – MARCH 24, 2008**

Please refer to the attached worksheet for the requested information. The number of participants is broken down between active employees and retirees. The allocation to Arizona is an approximation, since SERP is charged to Account 926 and is part of the Company's labor loading process. A full charged labor study for each year from 2003 to 2007 has not been done and would take a substantial amount of time to complete to determine the precise amount of SERP charged or allocable to Arizona for each year.

DECEMBER 2007 UPDATE
STF-6-41
SHEET 1 OF 1

**SOUTHWEST GAS CORPORATION
SERP PARTICIPANTS AND COSTS
2003 THROUGH 2007**

Line No.	Description (a)	2003 (b)	2004 (c)	2005 (d)	2006 (e)	2007 (f)	Line No.
1	Number of Participants						1
2	Active	20	20	21	19	19	2
3	Retirees	31	33	32	34	33	3
	Total	51	53	53	53	52	
4	Total SERP Expense	\$ 2,675,034	\$ 2,735,084	\$ 3,062,112	\$ 3,357,013	\$ 3,231,516	4
5	Allocation to Paiute Pipeline (PP)/SGTC						5
6	SERP Allocated to PP/SGTC	5.20% \$ 139,102	4.91% \$ 134,293	4.91% \$ 150,350	4.11% \$ 137,973	4.12% \$ 133,138	6
7	SERP Expense Net of PP/SGTC	\$ 2,535,932	\$ 2,600,791	\$ 2,911,762	\$ 3,219,040	\$ 3,098,378	7
8	AZ Allocation Factor	57.38% \$ 1,455,118	57.66% \$ 1,499,616	57.10% \$ 1,662,616	56.81% \$ 1,828,736	56.78% \$ 1,759,259	8
9	SERP Allocated to AZ [1]						9

[1] Estimated SERP Expense Allocated to Arizona

243-020

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**RESIDENTIAL UTILITY CONSUMER OFFICE
DATA REQUEST NO. RUCO-1
(RUCO-1-1 THROUGH RUCO-1-22)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 27, 2007

Request No. RUCO-1-20:

SERP

Please provide the test-year recorded SERP expense and identify the account(s) where these expenses reside.

Respondent: Revenue Requirements

Response:

Please refer to WP Schedule C-2, Adj. 3, Sheet 8, Line 11. SERP is first recorded in Account 926, then loaded to all accounts charged with labor during the labor loading process.

294-008

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-9
(ACC-STF-9-1 THROUGH ACC-STF-9-21)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 28, 2008

Request No. ACC-STF-9-8:

Supplemental Executive Retirement Expense (SERP). Refer to the response to STF-1-49 and WP Schedule C-2, Adjustment 3, sheet 8, line 11, columns C, D and F. (a) Please confirm that the total Arizona related SERP test year expenses were \$1,395,781 (column C) plus \$54,102 (column D), plus the \$866,016 system allocable amount. (b) In addition, please clarify whether the System Allocable amount of \$866,016 is prior to, or after applying the Arizona four-factor percentage of 56.70%. If this amount is prior to applying the 56.70%, please confirm that the Arizona System Allocable expense included by Southwest in test year expenses is \$491,031. (c) If the system allocable SERP charged to Arizona operations is anything other than the \$866,016 or \$491,031, please identify, quantify and explain in detail.

Respondent: Revenue Requirements

Response:

Attached is a schedule showing the amount of SERP in Arizona expenses. For an explanation of how System Allocable SERP (and other benefits) are allocated to Arizona, please refer to the Company's response to data request no. STF-11-13.

**SOUTHWEST GAS CORPORATION
ARIZONA
SERP
IN RESPONSE TO STF-9-8**

Line No.	Description	Reference [1]	Arizona	Corp. Direct Arizona	System Allocable	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	As Filed	Sh 8, Ln 11	\$ 1,395,781	\$ 54,102	\$ 866,016	1
2	Percent O&M	Sh 18, Ln 11; Sh 28, Lns 5(c) and (j)	80.09%	100%	96.16%	2
3	Subtotal	Ln 1 * Ln 2	\$ 1,117,881	\$ 54,102	\$ 832,761	3
4	Allocated to Paiute/SGTC	3.96%			\$ 32,977	4
5	Net of MMF Allocation	Ln 3 - Ln 4			799,784	5
6	Net of 4-Factor	Ln 5 * 56.70%			453,477	6
7	SERP		\$ 1,117,881	\$ 54,102	\$ 453,477	7

[1] All references are to WP Sch C-2, Adj 3 unless otherwise noted.

295-006

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-10
(ACC-STF-10-1 THROUGH ACC-STF-10-26)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 29, 2008

Request No. ACC-STF-10-6:

SERP. (a) Please explain and show in detail the impact on Southwest's filing, by account, if Southwest had followed completely the treatment for SERP expense, specified in Decision No. 68487 at pages 18-19. (b) Please provide all information, by account, necessary to apply similar treatment in the current rate case for SERP expense, specified in Decision No. 68487 at pages 18-29.

Respondent: Revenue Requirements

Response:

As calculated in the Company's response to data request no. STF-9-8, the amount of SERP expense in Arizona is \$1,625,460. Decision No. 68487 specified that SERP be removed from operating expenses. Please refer to the direct testimony of Ms. Laura Lopez Hobbs, which provides support for the reasonableness of the Company's request for executive total compensation.

Since SERP is a Company benefit that is loaded to all accounts that have charged labor, it will appear in many FERC accounts. Attached is a schedule that shows the amount of SERP expense in each FERC account. The first sheet shows the Arizona direct SERP loaded to each FERC account, and the second sheet shows the Corporate Direct and System Allocable SERP loaded to each FERC account (see bold amounts).

**SOUTHWEST GAS CORPORATION
ARIZONA
SERP
IN RESPONSE TO STF-10-6**

Line No.	Description (a)	Recorded Loading [1] (b)	SERP (c)	Line No.
1	SERP		\$ 1,395,781	1
	<u>Deferred and Other</u>			
2	Account 146	\$ 0	\$ 0	2
3	Account 163	826,097	30,022	3
4	Account 184	445,366	16,185	4
5	Account 426	0	0	5
6	Total Deferred and Other	\$ 1,271,463	\$ 46,207	6
	<u>Capital</u>			
7	Account 107	\$ 6,171,377	\$ 224,276	7
8	Account 108	202,319	7,353	8
9	Total Capital	\$ 6,373,696	\$ 231,629	9
10	Percent Capital & Other to Total [3]	19.91%	19.91%	10
	<u>Operations</u>			
11	Account 710	\$ 3,238,926	\$ 117,707	11
12	Account 871	6,883	250	12
13	Account 874	2,276,808	82,742	13
14	Account 875	687,367	24,980	14
15	Account 878	2,571,428	93,449	15
16	Account 879	3,006,578	109,263	16
17	Account 880	2,197,732	79,869	17
18	Account 901	1,514,770	55,049	18
19	Account 902	1,793,047	65,162	19
20	Account 903	5,308,467	192,917	20
21	Account 905	149,993	5,451	21
22	Account 908	130,980	4,760	22
23	Account 909	0	0	23
24	Account 910	0	0	24
25	Total Operating Expense	\$ 22,882,979	\$ 831,599	25

**SOUTHWEST GAS CORPORATION
ARIZONA
SERP
IN RESPONSE TO STF-10-6**

Line No.	Description (a)	Recorded Loading [1] (b)	SERP (c)	Line No.
	<u>Maintenance</u>			
1	Account 885	\$ 1,004,263	\$ 36,496	1
2	Account 886	9,807	356	2
3	Account 887	3,146,949	114,364	3
4	Account 889	538,862	19,583	4
5	Account 892	2,285,778	83,068	5
6	Account 893	472,870	17,185	6
7	Account 894	72,146	2,622	7
8	Account 935	348,661	12,671	8
9	Total Maintenance Expense	\$ 7,879,336	\$ 286,346	9
10	Total O & M	\$ 30,762,315	\$ 1,117,945	10
11	Percent O & M to Total	80.09%	80.09%	11
12	Total	\$ 38,407,474	\$ 1,395,781	12

SOUTHWEST GAS CORPORATION
SERP
BY JURISDICTION AND BY ACCOUNT
IN RESPONSE TO STF-10-6

Line No.	Description (a)	Corporate Direct to Arizona		System Allocable		Line No.
		Recorded Loading (b)	SERP (c)	Recorded Loading (d)	SERP (e)	
					Net of Palute (3.96%) (f)	
					Allocation Factor (g)	Allocated SERP (h)
						(f) x (g)
1	Corporate Loadings	\$ 54,102	\$ 866,016			1
2	Deferred and Other					
3	Account 146	\$ 0	\$ 0	\$ 34,586	\$ 1,438	2
4	Account 163	0	0	512,716	21,319	3
5	Account 182.3	0	0	22,541	937	4
6	Account 184	0	0	134,147	5,578	5
7	Account 188	0	0	0	0	6
8	Account 426	0	0	94,325	3,922	7
	Total Deferred and Other	\$ 0	\$ 0	\$ 798,315	\$ 33,195	8
9	Capital					
10	Account 107	\$ 0	\$ 0	\$ 531	\$ 22	9
	Total Capital	\$ 0	\$ 0	\$ 531	\$ 22	10
11	Percent Capital & Other to Total	0.00%	0.00%	3.84%	3.84%	11
12	Operations					
13	Account 813	\$ 230,046	\$ 9,659	\$ 29,121	\$ 1,211	12
14	Account 851	0	0	0	0	13
15	Account 870	85,307	3,545	0	0	14
16	Account 871	87,576	3,638	4,754	198	15
17	Account 879	0	0	0	0	16
18	Account 880	214,209	8,901	0	0	17
19	Account 901	0	0	0	0	18
20	Account 903	595,353	24,738	973,301	40,471	19
21	Account 908	58,904	2,448	0	0	20
22	Account 920	0	0	18,893,120	785,591	21
23	Account 922	0	0	0	0	22
24	Account 930	0	0	0	0	23
	Total Operating Expense	\$ 1,271,395	\$ 52,830	\$ 19,900,296	\$ 827,471	24
						\$ 450,429

Corporate

SOUTHWEST GAS CORPORATION
SERP
BY JURISDICTION AND BY ACCOUNT
IN RESPONSE TO STF-10-6

Line No.	Description (a)	Corporate Direct to Arizona		System Allocable		Allocation Factor (g)	Allocated SERP (h)	Line No.
		Recorded Loading (b)	SERP (c)	Recorded Loading (d)	Net of Paute (3.96%) (f)			
1	Maintenance							
2	Account 885	\$ 30,624	\$ 1,273	\$ 0	\$ 0	56.70%	\$ 0	1
3	Account 935	0	0	128,155	5,329	56.70%	2,902	2
3	Total Maintenance Expense	\$ 30,624	\$ 1,273	\$ 128,155	\$ 5,329	56.70%	\$ 2,902	3
4	Total O & M	\$ 1,302,019	\$ 54,102	\$ 20,028,451	\$ 832,799		\$ 453,331	4
5	Percent O & M to Total	100.00%	100.00%	96.16%	96.16%			5
6	Total	\$ 1,302,019	\$ 54,102	\$ 20,827,297	\$ 866,016		\$ 472,165	6

254-052

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-52:

Please refer to Ms. Aldridge's direct testimony, page 24. Please show in detail how the Company identified the portion of AGA costs that relate to marketing and lobbying activities. Include a copy of any and all source documents used to identify those percentages.

Respondent: Revenue Requirements

Response:

The portion of advertising and lobbying costs was provided to Southwest by the AGA in the attached document.

AMERICAN GAS ASSOCIATION
2007 BUDGET

	\$ 2007 <u>ALLOCATION</u>	% 2007 <u>ALLOCATION</u>
Advertising	\$345,000	1.39%
Corporate Affairs	\$2,099,000	8.44%
General & Administrative	\$4,665,000	18.77%
General Counsel	\$1,016,000	4.09%
Industry Finance & Administrative Programs	\$1,283,000	5.16%
Operations & Engineering Management	\$5,993,000	24.11%
Policy, Planning & Regulatory Affairs	\$3,669,000	14.76%
Public Affairs	<u>\$5,790,000</u>	<u>23.29%</u>
Total Budget	\$24,860,000	100.00%

Note:

AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 2% of member dues in 2007.

254-050

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-50:

Please refer to Ms. Aldridge's direct testimony, Exhibit RLA-2.

- a. Please provide a complete copy of the March 2005 Annual Audit report and show the percentages of AGA cost for each NARUC-designated functional category of AGA activities.
- b. Does Southwest Gas or AGA have more current information on the percentage of AGA costs in each NARUC-designated functional category of AGA activities? If so, please provide the most current information.

Respondent: Revenue Requirements

Response:

- a. Attached is the copy of the Annual Audit Report on the Expenditures of the American Gas Association (AGA) for the 12 month period ended December 31, 2002, dated March 2005. This report is the most recent audit report submitted to NARUC. According to the AGA, NARUC no longer requests that the AGA provide annual audit reports. The lobbying percentage is found on the page preceding the table of contents. The other percentages are found on page III-2.
- b. Attached is the updated budget information for 2008 provided by the AGA to Southwest.

AMERICAN GAS ASSOCIATION
2008 BUDGET

	\$ 2008 <u>ALLOCATION</u>	% 2008 <u>ALLOCATION</u>
Advertising	\$300,000	1.18%
Corporate Affairs	\$2,317,000	9.14%
General & Administrative	\$5,127,000	20.22%
General Counsel	\$1,056,000	4.17%
Industry Finance & Administrative Programs	\$852,000	3.36%
Operations & Engineering Management	\$5,505,000	21.71%
Policy, Planning & Regulatory Affairs	\$4,000,000	15.78%
Public Affairs	<u>\$6,195,000</u>	<u>24.44%</u>
Total Budget	\$25,352,000	100.00%

Note

AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 4% of member dues in 2008.

295-002

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-10
(ACC-STF-10-1 THROUGH ACC-STF-10-26)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 29, 2008

Request No. ACC-STF-10-2:

TRIMP. (a) Please explain and show in detail the impact on Southwest's filing, by account, if Southwest had followed completely the treatment for TRIMP, including TRIMP cost sharing, specified in Decision No. 68487 at pages 14-15. (b) Please provide all information, by account, necessary to apply similar treatment for TRIMP costs in the current case that was specified in Decision No. 68487 at pages 14-15.

Respondent: Revenue Requirements

Response:

a) Attached is the modification of Adjustment No. 9 as referenced above. The test year ending April 30, 2007, included \$348,690 in Account 887.0, Maintenance of Mains and recoveries of \$551,530 recorded in Account 407.3, Regulatory Amortizations. Both amounts would be adjusted to zero and a TRIMP surcharge would remain in effect presumably for another 36 months or indefinitely.

b) The currently effective DOT TRIMP surcharge is \$0.00072 per therm. Pursuant to Decision No. 68487, the surcharge will change on May 1, 2008, to clear the balance by February 28, 2009. The Company has calculated the May 1, 2008 rate to be \$0.00294 (Reference STF-9-18 (c) for the calculation). Attached please find file STF-10-2(b) showing the recovery of the current deferred costs and the projected costs assuming 50 percent recovery through the DOT TRIMP surcharge for an additional 36 months past the effective date of rates in this proceeding. The attached analysis uses November 1, 2008 as the effective date and October 31, 2011 as the sunset date. These calculations are based on a new DOT TRIMP surcharge rate each May 1 during this period.

**SOUTHWEST GAS CORPORATION
ARIZONA
STF-10-2 TRIMP
ADJUSTMENT NO. 9 MODIFICATION**

Line No.	Description (a)	Account Number (b)	Amount [1] (c)	Line No.
	Recorded Regulatory Amortization	407.3		
1	TRIMP		\$ 551,530	1
2	Demand Side Management (DSM)		642,568	2
3	PBOP		337,524	3
4	R&D		755,950	4
5			\$ 2,287,572	5
	Adjustments:			
6	R&D		\$ (755,950)	6
7	TRIMP		(551,530)	7
8	Demand Side Management (DSM)		(642,568)	8
9	Total Adjustments (Ln 6 + Ln 7 + Ln 8)		\$ (1,950,048)	9
10	Annualized Regulatory Amortization (Ln 5 + Ln 9)	407.3	\$ 337,524	10
11	Test Year Recorded TRIMP	887.0	\$ 348,690	11
12	TRIMP written off	887.0	(348,690)	12
13	Adjusted TRIMP Expense (Ln 11 + Ln 12)	887.0	\$ 0	13
14	Total Revenue Requirement Impact (Ln 9 + Ln 13)		\$ (1,950,048)	14

SOUTHWEST GAS CORPORATION
ARIZONA

Month	2004					2005					
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery	Ending Balance
January	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 414,227	\$ 3,288	\$ -	\$ -	\$ -	\$ 417,515
February	-	-	-	-	-	417,515	10,172	-	-	-	427,687
March	-	-	-	-	-	427,687	112,724	-	-	-	540,411
April	-	-	-	-	-	540,411	74,841	-	-	-	615,251
May	-	472	-	-	-	615,251	34,497	-	-	-	649,748
June	472	6,545	-	-	-	649,748	153,865	-	-	-	803,613
July	7,016	5,129	-	-	-	803,613	59,016	-	-	-	862,629
August	12,146	34,505	-	-	-	862,629	37,808	-	-	-	900,437
September	46,651	26,728	-	-	-	900,437	74,315	-	-	-	974,752
October	73,378	43,459	-	-	-	974,752	57,343	-	-	-	1,032,095
November	116,837	47,646	-	-	-	1,032,095	81,835	-	-	-	1,113,930
December	164,483	249,744	-	-	-	1,113,930	116,931	-	-	-	1,230,860

Month	2006					2007					
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery	Beginning Balance	100% Cost	50% Write-Off	Adjustment	\$ 0.00072 Recovery	Ending Balance
January	\$ 1,230,860	\$ 3,399	\$ -	\$ -	\$ -	\$ 679,585	\$ 1,697	\$ (92,152)	\$ -	\$ (90,809)	\$ 498,320
February	1,234,280	112,185	-	-	-	488,320	88,940	(948)	-	(77,638)	509,776
March	1,346,445	89,028	(57,792)	(615,430)	(33,880)	508,776	51,725	(44,970)	-	(55,745)	480,767
April	728,371	14,518	(15,816)	-	(53,530)	480,787	295,845	(25,863)	-	(36,334)	894,435
May	673,741	78,761	(36,155)	-	(39,244)	684,535	219,061	(147,922)	-	(35,480)	730,084
June	677,103	25,799	(39,380)	-	(41,873)	730,084	563,459	(109,530)	-	(33,361)	1,150,662
July	621,648	11,717	(12,869)	-	(32,941)	1,150,662	181,870	(281,730)	-	(32,909)	987,893
August	587,524	25,739	(5,858)	-	(31,285)	997,893	382,430	(80,935)	-	(32,385)	1,287,003
September	576,119	61,418	(12,869)	-	(11,353)	1,287,003	606,096	(191,215)	-	(30,794)	1,851,090
October	613,312	140,790	(30,708)	-	(32,705)	1,851,090	211,300	(303,048)	-	(20,990)	1,538,352
November	590,690	53,182	(20,395)	-	(38,631)	1,538,352	145,226	(105,650)	-	(27,071)	1,550,858
December	584,845	184,305	(28,561)	-	(62,974)	1,550,858	17,513	(72,613)	-	(45,145)	1,450,612

[1] To write off 50% of 2004 & 2005 program costs incurred prior to implementing the deferred accounting and monthly surcharge in March 2006.

TACHMENT
STF-10.2 (B)

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2
TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TRIMP)
RECOVERY OF ACCOUNT 182.3 BALANCE @ APRIL 30, 2008 PLUS
50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATES EFFECTIVE MAY 1, 2008-2011

Month	2008					2009					2010					2011								
	Beginning Balance	100% Cost	50% Write-Off	Adjustment	Recovery	Ending Balance	Beginning Balance	100% Cost	50% Write-Off	Adjustment	Recovery	Ending Balance	Beginning Balance	100% Cost	50% Write-Off	Adjustment	Recovery	Ending Balance	Beginning Balance	100% Cost	50% Write-Off	Adjustment	Recovery	Ending Balance

Note A: Monthly cost estimated based on Company requested amount divided by 12 and ending on October 31, 2008, or the month that new rates become effective.

[1] Current \$0.00072 Recovery Rate through April. Effective May 1, 2008, Recovery Rate \$0.00294.

[2] Actual January 2008 cost, write-off and recovery amounts.

[3] Effective May 1, 2009, Recovery Rate \$0.00015

[4] Effective May 1, 2010, Recovery Rate \$0.00082

[5] Effective May 1, 2011, Recovery Rate \$0.00083

CHWENT
STF-10-2 (B)

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2
DOT PIPELINE SAFETY SURCHARGE CALCULATION

**RECOVERY OF ACCOUNT 182.3 BALANCE @ APRIL 30, 2008 PLUS
50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATE EFFECTIVE MAY 1, 2008**

Line No.	Calendar Year (a)	Annual Estimates [1] (b)	Monthly Estimates (c) (b) / 12	Disallowed (c)	Recoverable (d)	Projected Therm Sales [2] (e)	Calculated Per Therm Surcharge (f)	Line No.
1	2008	920,914	76,743					1
2	2009	920,914	76,743					2
3	2010	920,914	76,743					3
4	2011	920,914	76,743					4
5	Apr 2008	1,375,007 [3]			1,375,007			5
6	May-Dec 2008	613,943 [4]	50%		306,971	392,332,760		6
7	Jan-Feb 2009	153,486 [5]	50%		76,743	206,644,670		7
10	Total				\$ 1,758,722	598,977,430	0.00294	10
11					Average Annual Use Per Customer	332		11
12					Annual DOT Surcharge Per Customer \$	0.98		12
13					Monthly DOT Surcharge Per Customer \$	0.08		13

[1] Based on 2007 Actual Costs as Requested in Adj 9.

[2] Rate Case Volumes

[3] Balance @ April 30, 2008 (100%) Recoverable

[4] May through December Projected Volumes

[5] 2 Months Projected Volumes

v9g011

May 1, 2008 Calculation

A JHMENT
STF-10-2 (B)

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2

TRIMP RECOVERY DOLLARS AND RATE PER THERM

Test Year	Rate Case	DOT	DOT	DOT
	Volumes	Rate	Recovery	Recovery
January	108,927,515	\$	0.00294	\$
February	97,717,155		0.00294	320,247
March	83,220,367		0.00294	287,288
April	60,913,121		0.00294	244,668
May	49,936,376		0.00294	179,085
June	41,594,843		0.00294	146,813
July	38,828,036		0.00294	122,289
August	36,646,593		0.00294	114,154
September	38,153,138		0.00294	107,741
October	41,933,546		0.00294	112,170
November	54,244,256		0.00294	123,285
December	90,995,972		0.00294	159,478
	<u>743,110,918</u>			<u>267,528</u>
				<u>\$ 2,184,746</u>

v9g01!

May 1, 2008 Rate Per Therm

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2
DOT PIPELINE SAFETY SURCHARGE CALCULATION**

**50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATE EFFECTIVE MAY 1, 2009**

Line No.	Calendar Year (a)	Annual Estimates [1] (b)	Monthly Estimates (c) (b) / 12	Disallowed (c)	Recoverable (d)	Projected Therm Sales [2] (e)	Calculated Per Therm Surcharge (f)	Line No.
1	2009	920,914	76,743					1
2	2010	920,914	76,743					2
3	2011	920,914	76,743					3
4	Apr 2009 Deferred Bal	(349,282)			(349,282)			4
5	May-Dec 2009	613,943 [3]	50%		306,971	392,332,760		5
6	Jan-Apr 2010	306,971 [4]	50%		153,486	350,778,158		6
7	Total				\$ 111,175	\$ 743,110,918	\$ 0.00015	7
8					Average Annual Use Per Customer	332		8
9					Annual DOT Surcharge Per Customer \$	0.05		9
10					Monthly DOT Surcharge Per Customer \$	0.00		10

[1] Based on 2007 Actual Costs as Requested in Adj 9.

[2] Rate Case Volumes

[3] May through December Projected Volumes

[4] January through April Projected Volumes

CHMENT
STF-10-2 (B)

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2**

TRIMP RECOVERY DOLLARS AND RATE PER THERM

Test Year	Rate Case	Volumes	DOT Rate	DOT Recovery
January		108,927,515	\$ 0.00015	\$ 16,339
February		97,717,155	0.00015	14,658
March		83,220,367	0.00015	12,483
April		60,913,121	0.00015	9,137
May		49,936,376	0.00015	7,490
June		41,594,843	0.00015	6,239
July		38,828,036	0.00015	5,824
August		36,646,593	0.00015	5,497
September		38,153,138	0.00015	5,723
October		41,933,546	0.00015	6,290
November		54,244,256	0.00015	8,137
December		90,995,972	0.00015	13,649
		<u>743,110,918</u>	<u>\$</u>	<u>111,467</u>

v9g01l

May 1, 2009 Rate Per Therm

A JHMENT
STF-10-2 (B)

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2
DOT PIPELINE SAFETY SURCHARGE CALCULATION**

**50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATE EFFECTIVE MAY 1, 2010**

Line No.	Calendar Year (a)	Annual Estimates [1] (b)	Monthly Estimates (c) (b) / 12	Disallowed (c)	Recoverable (d)	Projected Therm Sales [2] (e)	Calculated Per Therm Surcharge (f)	Line No.
1	2010	920,914	76,743					1
2	2011	920,914	76,743					2
3	Apr 2010 Deferred Bal	(291)			(291)			3
4	May-Dec 2010	613,943 [3]	50%		306,971	392,332,760		4
5	Jan-Apr 2011	306,971 [4]	50%		153,486	350,778,158		5
6	Total				\$ 460,166	743,110,918 \$	0.00062	6
7					Average Annual Use Per Customer	332		7
8					Annual DOT Surcharge Per Customer \$	0.21		8
9					Monthly DOT Surcharge Per Customer \$	0.02		9

[1] Based on 2007 Actual Costs as Requested in Adj 9.

[2] Rate Case Volumes

[3] May through December Projected Volumes

[4] January through April Projected Volumes

v9g01!

May 1, 2010 Calculation

CHMENT
STF-10-2 (B)

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2

TRIMP RECOVERY DOLLARS AND RATE PER THERM

Test Year	Rate Case	Volumes	DOT	Rate	DOT	Recovery
January		108,927,515	\$	0.00062	\$	67,535
February		97,717,155		0.00062		60,585
March		83,220,367		0.00062		51,597
April		60,913,121		0.00062		37,766
May		49,936,376		0.00062		30,961
June		41,594,843		0.00062		25,789
July		38,828,036		0.00062		24,073
August		36,646,593		0.00062		22,721
September		38,153,138		0.00062		23,655
October		41,933,546		0.00062		25,999
November		54,244,256		0.00062		33,631
December		90,995,972		0.00062		56,418
		<u>743,110,918</u>			\$	<u>460,729</u>

v9g011

May 1, 2010 Rate Per Therm

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2
DOT PIPELINE SAFETY SURCHARGE CALCULATION**

**50% TRIMP COST RECOVERY THROUGH DOT SURCHARGE
NEW RATE EFFECTIVE MAY 1, 2011**

Line No.	Calendar Year (a)	Annual Estimates (b)	Monthly Estimates (c) (b) / 12	Disallowed (c)	Recoverable (d)	Projected Therm Sales [2] (e)	Calculated Per Therm Surcharge (f)	Line No.
1	2011	920,914	76,743					1
2	Apr 2011 Deferred Bal	(563)						2
3	May-October 2011	460,457 [3]	50%		230,228	247,092,532		3
4	Total				\$ 229,665	247,092,532 \$	0.00093	4
5						Average Annual Use Per Customer	332	5
6						Annual DOT Surcharge Per Customer \$	0.31	6
7						Monthly DOT Surcharge Per Customer \$	0.03	7

[1] Based on 2007 Actual Costs as Requested in Adj 9.

[2] Rate Case Volumes

[3] May through October Projected Volumes

3HMENT
STF-10-2 (B)

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-10-2

TRIMP RECOVERY DOLLARS AND RATE PER THERM				
Test Year	Rate Case	DOT	DOT	DOT
	Volumes	Rate	Recovery	
January	108,927,515	\$	0.00093	\$
February	97,717,155		0.00093	101,303
March	83,220,367		0.00093	90,877
April	60,913,121		0.00093	77,395
May	49,936,376		0.00093	56,649
June	41,594,843		0.00093	46,441
July	38,828,036		0.00093	38,683
August	36,646,593		0.00093	36,110
September	38,153,138		0.00093	34,081
October	41,933,546		0.00093	35,482
November	54,244,256		0.00093	38,998
December	90,995,972		0.00093	50,447
	743,110,918	\$		84,626
				691,093

v9g01!

May 1, 2011 Rate Per Therm

294-014

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-9
(ACC-STF-9-1 THROUGH ACC-STF-9-21)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 28, 2008

Request No. ACC-STF-9-14:

Injuries and Damages. Refer to the response to STF-1-66 and WP Schedule C-2, sheet 72, Adjustment 10, line 12. Please confirm that the test year amount of \$450,132 shown on the referenced workpaper relates to Arizona jurisdiction only. If so, please reconcile this amount to the response to STF-1-66, which indicates test year expense of \$472,757 for Arizona jurisdiction. If not, please identify the Arizona expense amount and explain fully.

Respondent: Revenue Requirements

Response:

Attached is a corrected Attachment to the Company's response to STF-1-66. A negative \$66,728 recorded in May 2006 to Self-Insured Retention was listed under Southern Nevada instead of Arizona. The net recorded test year Arizona activity for Self-Insured Retention is a negative \$558,765, as shown on the corrected schedule attached and in Schedule C-2, Adjustment 10, Line 13 (f). Please refer to the Company's response to STF-9-15 for detail of test year charges for Arizona Self-Insured Retentions.

The negative \$450,132 shown on WP Schedule C-2, Sheet 72, Adjustment 10, Line 12 should have been a negative \$449,856, which is the number shown on schedule C-2, Adjustment No. 10, Line 14(f). The difference is due to use of a rounded Arizona Four Factor in the workpaper. The negative \$449,856 is the net of the recorded \$220,000 System Allocable Self-Insured Retention shown on Line 9 (d) of Schedule C-2, Adjustment less the Paiute MMF allocation and then allocated to Arizona to net \$108,909. When the test year recorded negative \$558,765 is added to the positive \$108,909, the net is a negative \$449,856.

(Continued on Page 2)

294-014
Page 2

Response to ACC-STF-9-14: (continued)

The \$472,757 shown on the Company's response to STF-1-66 should have been \$406,029 and is the net of three numbers. The first number is \$467,270, which represents the test year recorded legal and other fees. The Company is not proposing any adjustment to this amount and is requesting that the test year amounts be used to establish rates in this proceeding. The second number is \$497,524, which represents the test year recorded amounts related to workers compensation. The Company is self-insured for this expense and is requesting the recorded amount of \$497,524 for inclusion in rates in this proceeding.

The third number is the negative \$558,765, which is the net test year activity for Self-Insured Retentions and is the subject of Adjustment No. 10. The Company's adjustment consists of two parts: 1) removal of the negative recorded \$558,765 and replacement with a 10-year average of total Company Self-Insured Retentions after allocation to Paiute and 2) the Arizona Four Factor applied to the balance net of Paiute allocation.

Attached are two schedules detailing the flow of the Account 925 activity from recorded test year April 2007, adjustments and the adjusted amount requested. The first schedule is per the Company's filing, which leaves the negative number under the direct category and increases the system allocable portion accordingly in order to derive the Company's requested amount. The second schedule demonstrates how the adjustment would look if the Direct Account 925 category of the schedule removed the negative \$558,765 leaving \$964,794 direct instead of the filed \$406,029 and reduced the system allocable portion accordingly and requested an Arizona allocation of system allocable of \$7,204,060, instead of the filed \$7,762,825. In both instances, the Company's total direct and allocated request would be \$8,168,854.

A third set of schedules adjust the Injuries and Damages expense to reflect the \$300,000 reclass error discussed in the Company's response to STF-1-53 (2) and STF-9-15. A \$300,000 adjustment to Self-Insured Retentions was recorded as a credit to Account 923, Outside Services, when it should have been a credit to Account 925. The Arizona recorded negative \$558,765 activity should have been a negative \$858,765.

Finally, attached is the monthly activity for the calendar years 2004 - 2006 and the test year ended April 2007 for all Southwest rate jurisdictions and System Allocable expense in the categories detailed in the Company's response to STF-1-66.

Summary of A. 25 Per Filing

ARIZONA
DATA REQUEST NO. STF-9-14
DETAIL OF RECORDED TEST YEAR AND ADJUSTMENTS TO PROPOSED ARIZONA INJURIES AND DAMAGES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007 AS ADJUSTED
REDONE TO REFLECT PROPOSED SELF-INSURED ADJUSTMENT AS A DIRECT AND SYSTEM ALLOCABLE ADJUSTMENT

Description	Account Number	Division	Recorded April 2007	Out of Period Adj. 7	Palate MMF Alloc. Adj. 12	Self-Insurance Adj. 10	Self-Insurance Adj. 10	Total Adjust.	Adjusted Total	Other Juris.	Direct Arizona	Arizona Allocation 56.70%	Total Arizona Adjusted
Legal and Other Costs	92500001	Tot. AZ	\$ 467,269					\$ 0	\$ 467,269	\$ 0	\$ 467,269	\$ 0	\$ 467,269
Reserve for Self-Insurance	92500001		(558,765)				\$ 558,765	\$ 558,765	0	0	0	0	0
Self-Insured Workmen's Comp	92501832		\$ 406,029	\$ 0	\$ 0	\$ 558,765	\$ 0	\$ 558,765	\$ 984,794	\$ 0	\$ 984,794	\$ 0	\$ 984,794
Legal and Other Costs	92500001	No. CA	\$ 1,319					\$ 0	\$ 1,319	\$ 1,319	\$ 0	\$ 0	\$ 0
Reserve for Self-Insurance	92500001		0					0	0	0	0	0	0
Self-Insured Workmen's Comp	92501832		\$ 4,821	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 4,821	\$ 4,821	\$ 0	\$ 0	\$ 0
Legal and Other Costs	92500001	So. CA	\$ 58,225					\$ 0	\$ 58,225	\$ 58,225	\$ 0	\$ 0	\$ 0
Reserve for Self-Insurance	92500001		0					0	0	0	0	0	0
Self-Insured Workmen's Comp	92501832		\$ 180,213	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 180,213	\$ 180,213	\$ 0	\$ 0	\$ 0
Legal and Other Costs	92500001	No. NV	\$ 7,011					\$ 0	\$ 7,011	\$ 7,011	\$ 0	\$ 0	\$ 0
Reserve for Self-Insurance	92500001		0					0	0	0	0	0	0
Self-Insured Workmen's Comp	92501832		\$ 123,529	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 123,529	\$ 123,529	\$ 0	\$ 0	\$ 0
Legal and Other Costs	92500001	So. NV	\$ 112,481					\$ 0	\$ 112,481	\$ 112,481	\$ 0	\$ 0	\$ 0
Reserve for Self-Insurance	92500001		175,000					0	175,000	175,000	0	0	0
Self-Insured Workmen's Comp	92501832		\$ 100,298	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 100,298	\$ 100,298	\$ 0	\$ 0	\$ 0
Legal and Other Costs	92500001	Common	\$ 179,014					\$ 0	\$ 179,014	\$ 0	\$ 0	\$ 101,501	\$ 101,501
Reserve for Self-Insurance	92500001		200,000				(200,000)	\$ 3,136,861	\$ 3,136,861	\$ 0	\$ 0	\$ 1,778,600	\$ 1,778,600
Self-Insured Workmen's Comp	92501832		\$ 23,243	\$ 446,779	\$ 14,654	\$ 7,920	\$ 0	\$ 446,779	\$ 9,738,915	\$ 9,738,915	\$ 5,521,965	\$ 5,521,965	\$ 5,521,965
Allocation - Palate	92501800		\$ (395,033)	\$ 446,779	\$ 14,654	\$ (192,080)	\$ 0	\$ 22,574	\$ (372,459)	\$ 0	\$ 0	\$ (211,184)	\$ (211,184)
Total Account 925			\$ 10,468,287	\$ 446,779	\$ 14,654	\$ 366,585	\$ 3,136,861	\$ 3,984,979	\$ 14,433,265	\$ 762,898	\$ 984,794	\$ 7,204,060	\$ 8,168,854
Sch. C-1 Sht 9 of 18 Line 9(c)			\$ 10,468,287	\$ 446,779	\$ 14,654								
Sch. C-1 Sht 11 of 18 Line 9(f)													
Sch. C-1 Sht 11 of 18 Line 9(i)													
Sch. C-1 Sht 13 of 18 Line 9(c) Adjusted													
Sch. C-1 Sht 13 of 18 Line 9(d)													
Sch. C-1 Sht 13 of 18 Line 9(e) Adjusted													
Sch. C-1 Sht 13 of 18 Line 9(k) Adjusted													
Sch. C-2 Adj. 10 Line 7(f)													
Sch. C-2 Adj. 10 Line 13(f)													
Sch. C-2 Adj. 10 Line 9(f)													
Sch. C-2 Adj. 10 Line 10(f)													

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Summary of Ac... 25 adj Redone

SOUTHWEST GAS CORPORATION
ARIZONA

DATA REQUEST NO. STF-9-14
ANALYSIS OF ACCOUNT 925 - SUMMARY OF ALL CHARGES AS ADJUSTED
FOR THE TWELVE MONTHS ENDED AS INDICATED
ADJUSTED FOR MAY 2006 CHARGE ORIGINALLY CHARGED TO ACCOUNT 923

Description	Account Number	Division	Sched C-1 Sheet 9 of 18 Line 9				Sched C-2 Sheet 1 of 1
			December 2004	December 2005	December 2006	April 2007	
Legal and Other Costs	92500001	Tot. AZ	\$ 1,408,734	\$ 952,287	\$ 628,934	\$ 487,269	L 13 Col F
Reserve for Self-Insurance	92500001		2,154,000	1,360,224	(1,042,268)	(858,765)	
Self-Insured Workmen's Comp	92501832		345,414	601,584	516,158	487,524	
			\$ 3,908,148	\$ 2,914,095	\$ 102,824	\$ 106,029	Col. D
Legal and Other Costs	92500001	No. CA	\$ 1,924	\$ 2,024	\$ 3,698	\$ 1,319	Col. E
Reserve for Self-Insurance	92500001		0	0	0	0	
Self-Insured Workmen's Comp	92501832		3,713	4,003	5,384	4,821	
			\$ 5,637	\$ 6,026	\$ 9,082	\$ 6,140	Col. E
Legal and Other Costs	92500001	So. CA	\$ 61,509	\$ 58,452	\$ 62,074	\$ 58,225	Col. E
Reserve for Self-Insurance	92500001		27,500	0	0	0	
Self-Insured Workmen's Comp	92501832		184,598	242,986	194,725	180,213	
			\$ 253,607	\$ 301,439	\$ 256,799	\$ 238,438	Col. E
Legal and Other Costs	92500001	No. NV	\$ 85,325	\$ 42,377	\$ 29,422	\$ 7,011	Col. E
Reserve for Self-Insurance	92500001		0	0	0	0	
Self-Insured Workmen's Comp	92501832		27,807	24,862	30,708	123,929	
			\$ 112,932	\$ 67,239	\$ 60,130	\$ 130,540	Col. E
Legal and Other Costs	92500001	So. NV	\$ 230,435	\$ 429,406	\$ 127,267	\$ 112,481	Col. E
Reserve for Self-Insurance	92500001		323,500	667,000	75,000	175,000	
Self-Insured Workmen's Comp	92501832		157,624	126,298	67,246	100,298	
			\$ 611,559	\$ 1,222,703	\$ 269,514	\$ 387,779	Col. E
Legal and Other Costs	92500001	Common	\$ (802,297)	\$ 157,051	\$ (31,805)	\$ 179,014	L 9 Col D
Reserve for Self-Insurance (925000001)	92500001		275,000	10,367,500	200,000	200,000	
Self-Insured Workmen's Comp (92501832)	92501832		15,085	17,741	14,714	23,243	
Insurance (92501831)	92501831		6,875,409	8,691,167	9,584,066	9,292,136	Col. F
Allocation - Paiute (92501900)	92501900		(317,404)	(803,610)	(257,656)	(395,033)	
			\$ 5,845,794	\$ 18,429,849	\$ 9,509,518	\$ 9,299,360	
Total Account 925			\$ 10,737,676	\$ 22,941,351	\$ 10,207,867	\$ 10,168,287	Col. C
Adjusted for a June 2006 Reversal of a Self-Insured Retention from Account to Account 925.							
Recorded					(742,268)	(558,765)	
Reclassification of May 2206 charge to Account 923					(300,000)	(300,000)	
Adjusted TME Dec. 2006 and TME April 2007					(1,042,268)	(858,765)	

Detail 2004-2007 Apr. 07 Adj.

ARIZONA
DATA REQUEST NO. STF-9-14
DETAIL OF RECORDED TEST YEAR AND ADJUSTMENTS TO PROPOSED ARIZONA INJURIES AND DAMAGES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007 AS ADJUSTED
REDUE TO REFLECT THE ACCOUNTING \$300,000 ERROR REFERENCE IN STF-1-53(2)

Description	Account Number	Division	Recorded April 2007	Out of Period Adj. 7	Palute MMF Alloc. Adj. 12	Self-Insurance Adj. 10	Self-Insurance Adj. 10	Total Adjust.	Adjusted Total	Other Juris.	Direct Arizona	Arizona Allocation 56.70%	Total Arizona Adjusted
Legal and Other Costs	92500001	Tot. AZ	\$ 467,269					\$ 0	\$ 467,269	\$	\$ 467,269	\$	\$ 467,269
Reserve for Self-Insurance	92500001		(858,765)				858,765	0	0		0		0
Self-Insured Workmen's Comp	92501832		497,524				0	497,524	497,524		497,524		497,524
			\$ 108,029	\$ 0	\$ 0	\$ 858,765	\$ 0	\$ 858,765	\$ 984,784	\$	\$ 984,784	\$	\$ 984,784
Legal and Other Costs	92500001	No. CA	\$ 1,319					\$ 0	\$ 1,319	\$ 1,319			
Reserve for Self-Insurance	92500001		0				0	0	0				
Self-Insured Workmen's Comp	92501832		4,821				0	4,821	4,821				
			\$ 6,140	\$ 0	\$ 0	\$ 0	\$ 0	\$ 6,140	\$ 6,140				
Legal and Other Costs	92500001	So. CA	\$ 58,225					\$ 0	\$ 58,225	\$ 58,225			
Reserve for Self-Insurance	92500001		0				0	0	0				
Self-Insured Workmen's Comp	92501832		180,213				0	180,213	180,213				
			\$ 238,438	\$ 0	\$ 0	\$ 0	\$ 0	\$ 238,438	\$ 238,438				
Legal and Other Costs	92500001	No. NV	\$ 7,011					\$ 0	\$ 7,011	\$ 7,011			
Reserve for Self-Insurance	92500001		0				0	0	0				
Self-Insured Workmen's Comp	92501832		123,529				0	123,529	123,529				
			\$ 130,540	\$ 0	\$ 0	\$ 0	\$ 0	\$ 130,540	\$ 130,540				
Legal and Other Costs	92500001	So. NV	\$ 112,481					\$ 0	\$ 112,481	\$ 112,481			
Reserve for Self-Insurance	92500001		175,000				0	175,000	175,000				
Self-Insured Workmen's Comp	92501832		100,298				0	100,298	100,298				
			\$ 387,779	\$ 0	\$ 0	\$ 0	\$ 0	\$ 387,779	\$ 387,779				
Legal and Other Costs	92500001	Common	\$ 179,014					\$ 0	\$ 179,014	\$	\$	\$ 101,501	\$ 101,501
Reserve for Self-Insurance	92500001		200,000			(200,000)	3,108,048	2,908,048	3,108,048			1,762,263	1,762,263
Self-Insured Workmen's Comp	92501832		23,243				0	23,243	23,243			13,179	13,179
Insurance	92501831		9,292,136	446,779		7,920	446,779	9,738,915	9,738,915			5,521,965	5,521,965
Allocation - Palute	92501900		(395,033)		14,654	(192,080)	22,574	(372,459)	(372,459)			(211,184)	(211,184)
			\$ 9,299,360	\$ 446,779	\$ 14,654	\$ 3,108,048	\$ 3,377,401	\$ 12,676,761	\$ 12,676,761	\$ 0	\$ 0	\$ 7,187,723	\$ 7,187,723
Total Account 925			\$ 10,168,287	\$ 446,779	\$ 14,654	\$ 666,665	\$ 4,238,166	\$ 14,404,452	\$ 14,404,452	\$ 762,898	\$ 964,794	\$ 7,187,723	\$ 8,152,517
Sch. C-1 Sht 9 of 18 Line 9(c)													
Sch. C-1 Sht 11 of 18 Line 9(f)													
Sch. C-1 Sht 11 of 18 Line 9(f)													
Sch. C-1 Sht 13 of 18 Line 9(f)													
Sch. C-2 Adj. 10 Line 7(f)													
Sch. C-2 Adj. 10 Line 13(f)													
Sch. C-2 Adj. 10 Line 9(f)													
Sch. C-2 Adj. 10 Line 10(f)													

\$ 8,152,517

14,654

\$ 446,779

\$ 3,138,861

\$ (858,765)

\$ 200,000

\$ (7,920)

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Redue Reflect C-1-53(2) E (2)

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-14
ANALYSIS OF ACCOUNT 925 - SUMMARY OF ALL CHARGES
FOR THE TWELVE MONTHS ENDED DECEMBER 2004**

Description	Division	Total	Jan 04	Feb 04	Mar 04	Apr 04	May 04	Jun 04	Jul 04	Aug 04	Sep 04	Oct 04	Nov 04	Dec 04
Security, Safety, Misc	Tot. AZ	1,408,734	188,655	192,713	159,757	128,503	138,214	105,374	37,385	76,654	90,205	70,209	122,197	98,866
Reserve for Self-Insurance		2,154,000	25,000	(115,000)	50,000	0	1,150,000	0	(270,750)	0	770,500	0	532,500	11,750
Self-Insured Workmen's Comp		3,454,414	93,491	48,582	807,929	18,579	(812,115)	35,814	40,800	38,889	20,274	51,257	37,558	(32,724)
		3,908,148	307,146	126,375	1,017,686	147,083	476,089	141,188	(192,565)	112,543	880,980	121,466	692,256	77,892
Security, Safety, Misc	No. CA	1,924	0	0	1,924	0	0	0	0	0	0	0	0	0
Reserve for Self-Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
Self-Insured Workmen's Comp		3,713	0	84	976	0	0	1,877	0	0	976	0	0	0
		5,837	0	84	2,900	0	0	1,877	0	0	976	0	0	0
Security, Safety, Misc	So. CA	61,509	250	409	0	1,832	8,253	7,264	11,071	11,482	14,795	2,110	3,287	756
Reserve for Self-Insurance		27,500	0	0	0	0	0	0	75,000	0	0	0	0	(47,500)
Self-Insured Workmen's Comp		164,598	24,120	22,600	18,606	14,104	0	18,921	12,133	10,532	8,845	21,773	3,398	9,588
		253,607	24,370	23,009	18,606	15,936	8,253	26,185	98,204	22,014	23,640	23,883	6,683	(37,176)
Security, Safety, Misc	No. NV	85,325	6,236	152	20,137	20,997	4,400	0	4,707	2,209	23,108	224	1,224	1,930
Reserve for Self-Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
Self-Insured Workmen's Comp		27,607	8,306	392	2,404	3,948	7,504	1,201	(1,964)	1,018	1,148	1,184	1,188	1,298
		112,932	14,542	544	22,541	24,945	11,904	1,201	2,743	3,227	24,257	1,408	2,393	3,228
Security, Safety, Misc	So. NV	230,435	23,368	12,224	33,558	26,182	12,017	5,983	3,105	10,208	70,275	5,674	16,745	11,086
Reserve for Self-Insurance		323,500	(76,500)	0	0	0	0	0	0	350,000	0	0	0	50,000
Self-Insured Workmen's Comp		57,824	1,687	857	9,007	14,593	(49,081)	3,789	(5,782)	22,816	11,297	25,838	10,074	12,731
		611,559	(51,445)	13,081	42,566	40,775	(37,074)	9,782	(2,678)	382,822	81,572	31,512	26,816	73,827
Security, Safety, Misc	Common	(802,297)	(131,537)	8,144	43,394	(1,340)	5,884	(56,601)	(731,457)	9,089	9,259	10,116	5,888	26,055
Reserve for Self-Insurance		275,000	0	0	0	0	0	0	976,000	0	(200,000)	0	0	(100,000)
Self-Insured Workmen's Comp		15,085	9,274	339	(956)	273	(1,343)	80	225	907	4	8	2,003	4,292
Insurance		6,675,409	451,415	503,007	478,778	442,852	441,602	441,602	441,447	748,637	670,822	668,501	651,087	736,860
Allocation - Palute		(317,404)	(16,951)	(26,393)	(26,843)	(22,742)	(22,968)	(18,831)	(14,589)	(39,121)	(24,724)	(34,846)	(33,937)	(34,361)
		5,845,794	312,200	466,087	494,371	418,844	422,977	365,231	270,526	720,522	455,381	641,779	625,038	632,846
Total Account 925		10,737,676	606,813	649,190	1,598,670	647,583	882,159	545,283	176,231	1,241,129	1,486,785	820,049	1,353,187	750,617

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-9-14
ANALYSIS OF ACCOUNT 925 - SUMMARY OF ALL CHARGES
FOR THE TWELVE MONTHS ENDED DECEMBER 2005

Description	Division	Total	Jan 05	Feb 05	Mar 05	Apr 05	May 05	Jun 05	Jul 05	Aug 05	Sep 05	Oct 05	Nov 05	Dec 05
Security, Safety, Misc	Tot. AZ	952,287	100,412	89,984	51,217	97,001	107,925	106,640	101,071	79,853	85,676	42,975	82,309	27,224
Reserve for Self-Insurance		1,360,224	259,491	170,251	0	(78,097)	75,000	75,000	(7,154)	35,930	0	1,037,700	(176,000)	(30,897)
Self-Insured Workmen's Comp		801,584	43,290	16,856	54,430	80,432	28,982	28,500	41,660	17,276	24,801	220,282	73,541	(6,123)
		<u>2,814,095</u>	<u>403,183</u>	<u>276,892</u>	<u>105,647</u>	<u>78,336</u>	<u>208,888</u>	<u>210,207</u>	<u>135,577</u>	<u>133,059</u>	<u>110,277</u>	<u>1,300,967</u>	<u>(40,150)</u>	<u>(9,786)</u>
Security, Safety, Misc	No. CA	2,024	974	0	0	741	0	0	0	0	0	0	308	0
Reserve for Self-Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
Self-Insured Workmen's Comp	103	4,003	976	0	813	92	0	0	1,328	0	792	0	0	0
		<u>6,028</u>	<u>1,950</u>	<u>0</u>	<u>813</u>	<u>833</u>	<u>0</u>	<u>0</u>	<u>1,328</u>	<u>0</u>	<u>792</u>	<u>0</u>	<u>308</u>	<u>0</u>
Security, Safety, Misc	So. CA	58,452	9,173	0	7,048	310	6,049	6,218	2,857	0	16,570	1,119	9,108	0
Reserve for Self-Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
Self-Insured Workmen's Comp		242,985	24,282	9,850	12,855	24,153	12,103	10,672	16,415	65,740	17,375	13,087	43,175	(6,720)
		<u>301,438</u>	<u>33,456</u>	<u>9,850</u>	<u>19,903</u>	<u>24,463</u>	<u>18,152</u>	<u>16,890</u>	<u>19,273</u>	<u>65,740</u>	<u>33,945</u>	<u>14,208</u>	<u>52,283</u>	<u>(6,720)</u>
Security, Safety, Misc	No. NV	42,377	0	1,392	0	7,778	2,170	1,186	7,626	8,180	6,880	1,653	1,080	6,452
Reserve for Self-Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
Self-Insured Workmen's Comp		24,862	247	1,210	4,537	3,621	592	(1,704)	63	789	2,824	241	9,753	2,678
		<u>67,239</u>	<u>247</u>	<u>2,601</u>	<u>4,537</u>	<u>11,399</u>	<u>2,763</u>	<u>(538)</u>	<u>7,689</u>	<u>8,969</u>	<u>9,704</u>	<u>1,894</u>	<u>10,833</u>	<u>9,130</u>
Security, Safety, Misc	So. NV	429,406	60,416	25,748	44,889	23,810	7,891	53,659	18,319	13,897	15,370	10,781	15,654	139,592
Reserve for Self-Insurance		667,000	75,000	0	25,000	0	0	0	75,000	0	117,000	125,000	250,000	0
Self-Insured Workmen's Comp		126,298	4,318	7,826	22,651	8,320	22,633	(2,038)	22,821	11,211	8,550	802	10,141	9,282
		<u>1,222,703</u>	<u>139,734</u>	<u>33,374</u>	<u>92,340</u>	<u>32,131</u>	<u>30,324</u>	<u>51,621</u>	<u>116,139</u>	<u>24,908</u>	<u>140,920</u>	<u>136,583</u>	<u>275,795</u>	<u>148,854</u>
Security, Safety, Misc	Common	157,051	2,590	10,726	6,813	489	48,423	9,936	4,868	1,674	4,964	5,278	43,450	17,839
Reserve for Self-Insurance		10,367,500	(57,500)	0	325,000	0	0	0	0	0	100,000	0	0	10,000,000
Self-Insured Workmen's Comp		17,741	3,129	3,298	3,322	3,298	804	313	61	308	935	189	1,118	969
Insurance		8,691,167	643,416	741,374	663,416	644,687	641,285	636,185	641,906	867,654	774,927	789,347	792,800	854,168
Allocation - Palute		(803,610)	(25,145)	(32,104)	(28,628)	(27,560)	(29,347)	(27,473)	(27,491)	(36,960)	(37,435)	(33,780)	(35,580)	(462,101)
		<u>18,429,849</u>	<u>566,482</u>	<u>723,294</u>	<u>969,925</u>	<u>820,913</u>	<u>861,166</u>	<u>816,960</u>	<u>819,345</u>	<u>832,677</u>	<u>843,390</u>	<u>761,034</u>	<u>801,778</u>	<u>10,410,874</u>
Total Account 925		<u>22,941,351</u>	<u>1,145,071</u>	<u>1,046,011</u>	<u>1,193,166</u>	<u>768,075</u>	<u>922,292</u>	<u>897,141</u>	<u>899,352</u>	<u>1,063,363</u>	<u>1,139,028</u>	<u>2,214,663</u>	<u>1,100,847</u>	<u>10,552,341</u>

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-8-14
ANALYSIS OF ACCOUNT 925 - SUMMARY OF ALL CHARGES
FOR THE TWELVE MONTHS ENDED DECEMBER 2006

Description	Division	Total	Jan 06	Feb 06	Mar 06	Apr 06	May 06	Jun 06	Jul 06	Aug 06	Sep 06	Oct 06	Nov 06	Dec 06
Security, Safety, Misc Reserve for Self-Insurance	Tot. AZ	628,934	39,752	49,531	74,168	49,473	81,429	120,874	57,888	29,633	28,304	33,259	37,423	27,200
Self-Insured Workmen's Comp		(742,268)	13,497	18,000	0	(60,000)	0	(647,037)	0	0	(66,728)	0	(75,000)	75,000
		516,158	63,186	9,988	24,385	23,085	39,818	100,439	75,890	41,147	58,321	48,784	5,428	25,998
		402,824	116,435	77,529	98,552	12,558	121,247	(425,724)	133,578	70,780	19,888	82,024	(32,149)	128,099
Security, Safety, Misc Reserve for Self-Insurance	No. CA	3,698	1,913	0	466	0	0	0	0	0	0	0	0	1,319
Self-Insured Workmen's Comp		0	0	0	0	0	0	0	0	0	0	0	0	0
	103	5,384	825	73	825	0	0	1,750	0	0	825	0	0	1,087
		9,082	2,738	73	1,291	0	0	1,750	0	0	825	0	0	2,406
Security, Safety, Misc Reserve for Self-Insurance	So. CA	62,074	10,029	4,701	2,105	1,510	0	12,901	5,777	11,349	4,408	2,621	0	6,674
Self-Insured Workmen's Comp		0	0	0	0	0	0	0	0	0	0	0	0	0
		194,725	24,440	3,316	18,141	7,230	6,548	13,615	51,733	2,881	15,882	12,894	12,565	25,680
		256,799	34,469	8,017	20,246	8,740	8,548	26,518	57,510	14,230	20,290	15,315	12,565	32,353
Security, Safety, Misc Reserve for Self-Insurance	No. NV	29,422	4,144	6,848	6,875	4,883	1,267	167	2,721	1,127	75	0	1,047	270
Self-Insured Workmen's Comp		0	0	0	0	0	0	0	0	0	0	0	0	0
		30,708	4,148	554	4,047	5,122	98	5,761	(640)	899	1,029	1,508	89	8,315
		60,130	8,291	7,401	10,922	10,005	1,383	5,828	2,080	1,826	1,104	1,508	1,116	8,585
Security, Safety, Misc Reserve for Self-Insurance	So. NV	127,267	10,142	18,534	3,409	18,680	8,037	12,942	7,203	10,799	17,400	(5,600)	18,483	11,238
Self-Insured Workmen's Comp		75,000	0	0	0	0	0	0	0	0	0	0	0	75,000
		67,246	7,012	654	5,788	5,324	723	7,226	490	186	(2,357)	18,813	11,492	13,893
		269,514	17,153	19,188	9,198	22,005	8,760	20,168	7,693	10,985	15,043	11,214	27,975	100,131
Security, Safety, Misc Reserve for Self-Insurance	Common	(31,805)	16,709	8,101	4,335	8,162	16,086	13,672	21,511	29,437	9,163	767	41,973	(201,523)
Self-Insured Workmen's Comp		200,000	0	0	0	0	0	200,000	0	0	0	0	0	0
Insurance		14,714	1,294	350	160	699	181	1,560	247	0	0	0	6,047	4,176
Allocation - Paiute		9,584,066	805,593	883,220	805,437	1,139,733	311,864	776,072	775,991	880,276	801,008	828,318	787,669	810,865
		(257,656)	(33,438)	(36,202)	106,008	(48,633)	(13,322)	(40,247)	(32,389)	(36,122)	(32,893)	(33,580)	(33,930)	(24,909)
		9,509,518	790,158	855,470	915,941	1,101,961	314,808	951,057	765,360	863,591	777,278	793,506	801,760	588,609
Total Account 925		10,507,867	989,244	987,678	1,056,150	1,155,268	452,727	579,695	986,220	951,412	834,437	903,566	811,288	860,183

**SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-8-14
ANALYSIS OF ACCOUNT 925 - SUMMARY OF ALL CHARGES
FOR THE TWELVE MONTHS ENDED APRIL 2007**

Description	Division	Total	May 06	Jun 06	Jul 06	Aug 06	Sep 06	Oct 06	Nov 06	Dec 06	Jan 07	Feb 07	Mar 07	Apr 07
Security, Safety, Misc Reserve for Self-Insurance Self-Insured Workmen's Comp	Tot. AZ	467,268 (558,765) 497,524 406,029	81,429 0 39,818 121,247	120,874 (647,037) 100,439 (425,724)	57,888 0 75,890 133,578	29,833 0 41,147 70,780	28,304 (66,728) 58,321 19,896	33,259 0 48,764 82,024	37,423 (75,000) 5,428 (32,149)	27,200 75,000 25,898 128,099	18,661 0 40,387 59,048	11,012 80,000 19,839 110,851	14,110 75,000 29,727 118,837	7,477 0 12,068 19,543
Security, Safety, Misc Reserve for Self-Insurance Self-Insured Workmen's Comp	No. CA	1,319 0 4,821 8,140	0 0 0 0	0 0 1,750 1,750	0 0 0 0	0 0 0 0	0 0 825 825	0 0 0 0	0 0 0 0	1,319 0 1,087 2,406	0 0 73 73	0 0 0 0	0 0 1,087 1,087	0 0 0 0
Security, Safety, Misc Reserve for Self-Insurance Self-Insured Workmen's Comp	So. CA	58,225 0 180,213 238,438	0 0 6,548 6,548	12,801 0 13,815 26,516	5,777 0 51,733 57,510	11,349 0 2,881 14,230	4,408 0 15,882 20,290	2,621 0 12,894 15,515	0 0 12,565 12,565	6,674 0 25,680 32,353	660 0 11,459 12,118	7,812 0 6,046 13,858	660 0 9,525 10,185	5,384 0 11,586 16,950
Security, Safety, Misc Reserve for Self-Insurance Self-Insured Workmen's Comp	No. NV	7,011 0 123,529 130,540	1,267 0 98 1,363	167 0 5,761 5,928	2,721 0 (640) 2,080	1,127 0 698 1,828	75 0 1,029 1,104	0 0 1,508 1,508	1,047 0 69 1,116	270 0 8,315 8,585	89 0 388 474	80 0 610 690	170 0 985 1,154	0 0 104,712 104,712
Security, Safety, Misc Reserve for Self-Insurance Self-Insured Workmen's Comp	So. NV	112,481 175,000 100,298 387,779	8,037 0 723 8,760	12,942 0 7,226 20,168	7,203 0 490 7,693	10,799 0 186 10,985	17,400 0 (2,357) 15,043	(5,600) 0 16,813 11,214	16,483 0 11,492 27,975	11,238 75,000 13,893 100,131	17,255 0 4,270 21,525	7,105 100,000 26,774 133,879	5,220 0 13,046 18,266	4,399 0 7,742 12,140
Security, Safety, Misc Reserve for Self-Insurance Insurance Allocation - Paiute	Common	179,014 200,000 23,243 9,292,138 (395,033) 9,299,360	16,066 0 181 311,864 (13,322) 314,808	13,672 200,000 1,560 776,072 (40,247) 951,057	21,511 0 247 775,991 (32,389) 765,360	29,437 0 0 880,276 (36,122) 853,591	9,163 0 0 801,008 (32,893) 777,278	767 0 0 826,318 (33,930) 793,506	41,973 0 6,047 787,689 (33,930) 801,780	(201,523) 0 4,176 810,865 (24,909) 588,609	(1,951) 0 974 854,448 (34,991) 819,449	72,480 0 1,824 868,509 (39,467) 923,146	45,160 0 7,974 810,275 (35,400) 828,070	132,288 0 460 788,821 (37,784) 883,766
Total Account 925		10,468,287	452,727	579,695	966,220	951,412	834,437	903,566	811,288	860,183	911,687	1,182,423	977,538	1,037,111

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295-011

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-10
(ACC-STF-10-1 THROUGH ACC-STF-10-26)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 29, 2008

Request No. ACC-STF-10-11:

May 2005 leaking gas line fire. Refer to the 2006 financial statements at page 33, Insurance Coverage. (A) What amount of expense did Southwest include in the test year for litigation and settlement costs relating to the May 2005 leaking gas line fire related lawsuit? Identify the amounts by account. (B) Did the settlement in the fourth quarter of 2006 deplete the Company's maximum self-insured retention of \$11 million? If not, please identify the impact of the settlement on the self-insured retention. (C) Identify all expense in the test year, by account, related to accruals for the self-insured retention. (D) Please provide comparative amounts for each year, 2003, 2004, 2005, 2006 and 2007, by account, for charges to expenses for incurrence of self-insured liabilities. (E) Please provide comparative amounts for each year, 2003, 2004, 2005, 2006 and 2007, by account, for expenses related to the buildup of a balance in the self-insured retention account. (f) Please identify the monthly balances in the self-insured liability retention account from December 31, 2002 through December 31, 2007. (G) Please provide the information in parts c through f in Excel.

Respondent: Revenue Requirements

Response:

A) Attached is a workpaper that calculates the impact of the above referenced incident on the current rate case. The referenced incident is an example of a claim that can reach and even exceed the \$5 million aggregate.

B) Yes. The above incident exceeded the \$10 million aggregate in effect at the time of the occurrence.

C) Please refer to the Company's response to STF-9-14. Also please refer to Workpapers Sch. C-2, Adjustment No. 10, Sheets 72 to 75 for the net activity of self-insurance accruals for the 10 years ending April 2007.

D) and E) Please refer to the Company's response to subpart C) above.

F) Attached is a file providing the debit and credit activity for Account 228.2 for the period January 2003 through December 2007

SOUTHWEST GAS CORPORATION
DATA REQUEST NO ACC STF-10-11
ACCOUNT 228.2 ACCUMULATED PROVISION FOR INJURIES AND DAMAGES
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2007

Month	Year	Beg Balance	Debits	Credits	End Balance
January	2003	\$ (2,450,000)	\$ 0	\$ (1,025,000)	\$ (3,475,000)
February		(3,475,000)	0	(45,000)	(3,520,000)
March		(3,520,000)	0	(450,000)	(3,970,000)
April		(3,970,000)	50,000	0	(3,920,000)
May		(3,920,000)	100,000	0	(3,820,000)
June		(3,820,000)	0	0	(3,820,000)
July		(3,820,000)	0	(75,000)	(3,895,000)
August		(3,895,000)	236,000	0	(3,659,000)
September		(3,659,000)	399,491	0	(3,259,509)
October		(3,259,509)	0	0	(3,259,509)
November		(3,259,509)	175,000	0	(3,084,509)
December		(3,084,509)	0	(865,000)	(3,949,509)
January	2004	(3,949,509)	144,000	0	(3,805,509)
February		(3,805,509)	145,000	0	(3,660,509)
March		(3,660,509)	1,500,000	(50,000)	(2,210,509)
April		(2,210,509)	0	0	(2,210,509)
May		(2,210,509)	0	(300,000)	(2,510,509)
June		(2,510,509)	3,000	0	(2,507,509)
July		(2,507,509)	0	(370,000)	(2,877,509)
August		(2,877,509)	0	(350,000)	(3,227,509)
September		(3,227,509)	127,500	(570,500)	(3,670,509)
October		(3,670,509)	0	0	(3,670,509)
November		(3,670,509)	787,500	(532,500)	(3,415,509)
December		(3,415,509)	133,654	0	(3,281,855)
January	2005	(3,281,855)	17,500	(249,491)	(3,513,846)
February		(3,513,846)	32,500	(170,251)	(3,651,597)
March		(3,651,597)	247,500	(335,000)	(3,739,097)
April		(3,739,097)	79,097	0	(3,660,000)
May		(3,660,000)	0	(75,000)	(3,735,000)
June		(3,735,000)	36,500	(75,000)	(3,773,500)
July		(3,773,500)	0	(67,846)	(3,841,346)
August		(3,841,346)	25,000	(35,930)	(3,852,276)
September		(3,852,276)	122,000	(217,000)	(3,947,276)
October		(3,947,276)	0	(1,162,700)	(5,109,976)
November		(5,109,976)	57,320	(74,000)	(5,126,656)
December		(5,126,656)	1,049,000	(9,969,103)	(14,046,759)
January	2006	(14,046,759)	396,613	(13,497)	(13,663,643)
February		(13,663,643)	0	(18,000)	(13,681,643)
March		(13,681,643)	0	0	(13,681,643)
April		(13,681,643)	325,000	0	(13,356,643)
May		(13,356,643)	0	0	(13,356,643)
June		(13,356,643)	447,037	0	(12,909,606)
July		(12,909,606)	0	0	(12,909,606)
August		(12,909,606)	0	0	(12,909,606)
September		(12,909,606)	266,728	0	(12,642,878)
October		(12,642,878)	0	0	(12,642,878)
November		(12,642,878)	29,470,000	(19,028,052)	(2,200,930)
December		(2,200,930)	500,000	(150,000)	(1,850,930)
January	2007	(1,850,930)	0	0	(1,850,930)
February		(1,850,930)	76,177	(127,118)	(1,901,871)
March		(1,901,871)	0	(75,000)	(1,976,871)
April		(1,976,871)	0	0	(1,976,871)
May		(1,976,871)	250,000	(25,000)	(1,751,871)
June		(1,751,871)	0	0	(1,751,871)
July		(1,751,871)	44,405	(300,000)	(2,007,466)
August		(2,007,466)	49,500	(393,905)	(2,351,871)
September		(2,351,871)	0	0	(2,351,871)
October		(2,351,871)	0	(500,000)	(2,851,871)
November		(2,851,871)	426,871	0	(2,425,000)
December		(2,425,000)	1,000,000	(200,000)	(1,625,000)

SOUTHWEST GAS CORPORATION
ARIZONA
RESPONSE TO STAFF DATA REQUEST-10-11
MAY 2005 INCIDENT INCLUDED IN RATE CASE

Description	Recorded	Rate Case Adjustment	Adjusted	10-Yr Adjust	10-Yr Average	Paiute MMF	Net Syst. Alloc.	Arizona Allocation
Paiute/SWGT Allocation Arizona Allocation						-4.96%		56.70%
WP Sch. C-2, Adj. 10, Sheet 74 of 90 Ln 12	\$ 1,000,000	\$	\$ 1,000,000	10	\$ 100,000	\$ (4,960)	\$ 95,040	\$ 53,888
WP Sch. C-2, Adj. 10, Sheet 74 of 90 Ln 12	10,000,000	(5,000,000)	5,000,000	10	500,000	(24,800)	475,200	269,438
Total	\$ 11,000,000	\$ (5,000,000)	\$ 6,000,000		\$ 600,000	\$ (29,760)	\$ 570,240	\$ 323,326

Note: The actual amount paid out was greater than \$11 million. Southwest has stipulated to not devulge the actual amount of the payout other than the \$11 million. The self-insured aggregate at the time of the incident was \$10 million and Southwest charged this amount to expense along with the \$1 million self-insured retention. Effective with the August 1, 2005 plan year, the company has acquired an additional layer of insurance that covers the \$5,000,001 to \$10,000,000 portion of the aggregate. As such, southwest has used only the amounts under the currently effective insurance parameters in its proposed injuries and damages expense request.

254-060

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-60:

Injuries and damages. Refer to Mr. Mashas' testimony at pages 20-22.

- A. Please provide Southwest's total injuries and damages expense for each year, for the ten year period ending December 31, 2007.
- b. Please provide the annual amount of Southwest's "self insured accruals charged to Account 925" for each year in the ten year period ending December 31, 2007.
- c. Please provide the balance in Account 228.2, Accumulated Provision for Injuries and Damages, as of each of the following dates:
 - (1) 4/30/06,
 - (2) 4/30/07,
 - (3) 12/31/07.
- d. Please provide the Accumulated Deferred Income Tax balance related to the Accumulated Provision for Injuries and Damages, as of each of the following dates:
 - (1) 4/30/06,
 - (2) 4/30/07,
 - (3) 12/31/07.

Respondent: Revenue Requirements

(Continued on Page 2)

254-060
Page 2

Response to STF-6-60: (continued)

Response:

A. Attached is a schedule providing Southwest's charges to Account 925, Injuries and Damages, for the ten-year period 1998 through November 2007.

B. The attached file referenced in part (A) above provides the "self-insured" accruals for the ten-year period. The self-insured amounts are the net activity for each annual period referenced. Included in the Company's C-2 workpapers, sheets 72-75, is similar information by event, adjusted to reflect the current limits that exist during the test year.

C. Please refer to the attached schedule for the requested balances. November 2007 is provided in lieu of December 2007, since the latter is not yet available. December 2007 will be provided when available.

D. Please refer to the attached schedule for the requested balances. Deferred taxes are calculated using the composite Federal and Arizona state income tax rate of 39.529%. Again, November 2007 is provided in lieu of December 2007. December 2007 will be provided when available.

SOUTHWEST G. CORPORATION
ARIZONA
RESPONSE TO DATA REQUEST NO. STF-6-60
ANALYSIS OF ACCOUNT 925 - SUMMARY OF ALL CHARGES
FOR THE TWELVE MONTHS ENDED

Description	Account Number	Rate	Jrsdcn	1998	1999	2000	2001	2002	2003	2004	2005	2006	November 2007
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			264,437	153,710	875,475	996,458	685,155	1,080,359	1,408,734	952,287	628,934	257,105
Self-Insured Wk Cmp	92501832			751,083	500,000	1,080,545	426,955	350,000	1,941,509	2,154,000	1,360,224	(975,540)	588,829
				249,340	308,628	299,949	440,085	287,799	433,567	345,414	601,584	516,158	296,511
				\$ 1,264,860	\$ 962,338	\$ 2,255,969	\$ 1,863,498	\$ 1,322,954	\$ 3,435,435	\$ 3,908,148	\$ 2,914,095	\$ 169,552	\$ 1,142,244
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			(80,000)	0	79,375	0	(25,000)	0	1,924	2,024	3,698	1,319
Self-Insured Wk Cmp	92501832			0	0	2,318	4,088	4,871	20,030	3,713	4,003	5,384	4,807
				\$ (80,000)	\$ 0	\$ 81,693	\$ 4,088	\$ (20,129)	\$ 24,417	\$ 5,636	\$ 6,026	\$ 9,082	\$ 6,125
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			2,721	3,119	834	18,932	109,476	113,741	61,509	58,452	62,074	66,424
Self-Insured Wk Cmp	92501832			0	0	0	100,000	0	50,000	27,500	0	0	0
				54,996	108,281	159,702	91,922	94,661	83,617	164,598	242,986	194,725	147,687
				\$ 57,717	\$ 111,400	\$ 160,536	\$ 210,854	\$ 204,137	\$ 247,358	\$ 253,607	\$ 301,439	\$ 256,799	\$ 214,110
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			44,598	15,822	250,539	447,599	398,438	(22,637)	(852,361)	42,377	29,422	7,083
Self-Insured Wk Cmp	92501832			200,000	250,000	527,244	175,000	175,000	(125,000)	0	0	0	0
				166,645	147,545	204,755	39,058	39,132	89,385	27,608	24,862	30,708	131,630
				\$ 411,243	\$ 413,367	\$ 982,538	\$ 661,657	\$ 612,570	\$ (58,252)	\$ (624,754)	\$ 67,239	\$ 60,130	\$ 138,714
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			102,387	56,729	187,477	266,274	255,486	436,424	230,435	429,406	127,267	95,353
Self-Insured Wk Cmp	92501832			578,755	732,474	(317,925)	266,146	150,000	100,000	323,500	687,000	8,272	861,405
				65,891	434,794	160,412	108,369	117,616	278,340	57,624	126,298	67,246	103,275
				\$ 747,033	\$ 1,223,997	\$ 29,964	\$ 640,789	\$ 523,102	\$ 814,764	\$ 611,559	\$ 1,222,703	\$ 202,786	\$ 1,060,033
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			461,132	861,634	272,626	120,945	(50,247)	(26,922)	(64,610)	157,051	(31,605)	334,715
Self-Insured Wk Cmp	92501832			500,000	(200,000)	0	100,000	200,000	(300,000)	275,000	10,367,500	200,000	(25,500)
Insurance	92501831			156,577	151,793	(35,421)	(12,115)	2,860	17,330	15,085	17,741	14,714	15,644
Allocation - Paiute	92501900			1,791,769	1,815,117	1,625,174	2,198,218	2,985,552	4,288,440	6,675,409	8,691,167	9,584,066	9,801,997
				(157,663)	(254,979)	(109,694)	(137,202)	(180,260)	(204,911)	(317,404)	(803,610)	(255,113)	(414,956)
				\$ 2,751,815	\$ 2,373,565	\$ 1,752,685	\$ 2,269,846	\$ 2,957,895	\$ 3,773,937	\$ 6,583,480	\$ 18,429,849	\$ 9,512,061	\$ 9,711,900
Total Account 925				\$ 5,152,668	\$ 5,084,667	\$ 5,263,385	\$ 5,650,732	\$ 5,600,529	\$ 8,237,659	\$ 10,737,677	\$ 22,941,351	\$ 10,210,410	\$ 12,273,127
Total Company													
Legal and Other Costs	92500001												
Self-Insurance	92500001			875,275	1,091,014	1,586,951	1,850,208	1,398,308	1,565,352	985,630	1,641,598	819,790	761,999
Self-Insured Wk Cmp	92501832			1,949,838	1,282,474	1,369,239	1,068,101	850,000	1,666,509	2,780,000	12,394,724	(767,268)	1,424,534
Insurance	92501831			693,449	1,151,041	791,715	671,407	546,929	922,269	614,042	1,017,473	828,935	699,553
Allocation - Paiute	92501900			1,791,769	1,815,117	1,625,174	2,198,218	2,985,552	4,288,440	6,675,409	8,691,167	9,584,066	9,801,997
				(157,663)	(254,979)	(109,694)	(137,202)	(180,260)	(204,911)	(317,404)	(803,610)	(255,113)	(414,956)
Total Company				\$ 5,152,668	\$ 5,084,667	\$ 5,263,385	\$ 5,650,732	\$ 5,600,529	\$ 8,237,659	\$ 10,737,677	\$ 22,941,351	\$ 10,210,410	\$ 12,273,127

STF-6-60 A & B

%x01

**SOUTHWEST GAS CORPORATION
ARIZONA
RESPONSE TO STAFF DATA REQUEST NO. STF-6-60 C AND D
ACCOUNT 228 RESERVE FOR SELF-INSURANCE
ACCOUNT BALANCE AND DEFERRED TAX**

<u>Month - Year</u>	<u>Account 228</u>	<u>Deferred Tax</u>	<u>Net</u>	<u>Arizona Allocation</u>
Four Factor				56.70%
April 30, 2006	\$ 2,425,000	\$ (958,578)	\$ 1,466,422	\$ 831,461
April 30, 2007	1,976,870	(781,437)	1,195,433	677,811
November 30, 2007	13,356,643	(5,279,747)	8,076,896	4,579,600

%vx01!

STF-6-60 C & D

254-060

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-60:

Injuries and damages. Refer to Mr. Mashas' testimony at pages 20-22.

- A. Please provide Southwest's total injuries and damages expense for each year, for the ten year period ending December 31, 2007.
- B. Please provide the annual amount of Southwest's "self insured accruals charged to Account 925" for each year in the ten year period ending December 31, 2007.
- C. Please provide the balance in Account 228.2, Accumulated Provision for Injuries and Damages, as of each of the following dates:
 - (1) 4/30/06,
 - (2) 4/30/07,
 - (3) 12/31/07.
- D. Please provide the Accumulated Deferred Income Tax balance related to the Accumulated Provision for Injuries and Damages, as of each of the following dates:
 - (1) 4/30/06,
 - (2) 4/30/07,
 - (3) 12/31/07.

Respondent: Revenue Requirements

Response: **SUPPLEMENTAL ATTACHMENT – MARCH 25, 2008**

(Continued on Page 2)

254-060
Page 2

Response to ACC-STF-6-60: (continued)

A, B & D) The attached schedule, STF-6-60 Supplemental (a, b & d), has been updated through December 2007.

Please note: STF-6-60 (d) Revised Injuries and Damages is being provided to accurately reflect balances as of April 2006 and November 2007, which amounts were inadvertently switched when originally submitted.

C) Please refer to the Company's response to STF-10-11.

SOUTHWEST G. CORPORATION
ARIZONA
RESPONSE TO DATA REQUEST NO. STF-6-60
ANALYSIS OF ACCOUNT 925 - SUMMARY OF ALL CHARGES
FOR THE TWELVE MONTHS ENDED

Description	Account Number	Rate	Jrsdctn	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			264,437 \$	153,710 \$	875,475 \$	996,458 \$	685,155 \$	1,060,359 \$	1,408,734 \$	952,287 \$	628,934 \$	280,762
Self-Insured Wk Cmp	92501832			751,083	500,000	1,080,545	426,955	350,000	1,941,509	2,154,000	1,360,224	(975,540)	713,629
				249,340	308,628	299,949	440,085	287,799	433,567	345,414	601,584	516,158	293,006
				<u>\$ 1,264,860</u>	<u>\$ 962,338</u>	<u>\$ 2,255,969</u>	<u>\$ 1,863,498</u>	<u>\$ 1,322,954</u>	<u>\$ 3,435,435</u>	<u>\$ 3,908,148</u>	<u>\$ 2,914,095</u>	<u>\$ 169,552</u>	<u>\$ 1,287,397</u>
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			(80,000)	0	79,375	0	(25,000)	0	0	2,024	3,698	0
Self-Insured Wk Cmp	92501832			0	0	2,318	4,088	4,871	20,030	3,713	4,003	5,384	3,720
				<u>\$ (80,000)</u>	<u>\$ 0</u>	<u>\$ 81,693</u>	<u>\$ 4,088</u>	<u>\$ (20,129)</u>	<u>\$ 24,417</u>	<u>\$ 5,636</u>	<u>\$ 6,026</u>	<u>\$ 9,082</u>	<u>\$ 3,720</u>
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			2,721 \$	3,119 \$	834 \$	18,932 \$	109,476 \$	113,741 \$	61,509 \$	58,452 \$	62,074 \$	68,011
Self-Insured Wk Cmp	92501832			0	0	0	100,000	0	50,000	27,500	0	0	0
				54,998	108,281	159,702	91,922	94,661	83,617	164,598	242,986	194,725	126,864
				<u>\$ 57,717</u>	<u>\$ 111,400</u>	<u>\$ 160,536</u>	<u>\$ 210,854</u>	<u>\$ 204,137</u>	<u>\$ 247,358</u>	<u>\$ 253,607</u>	<u>\$ 301,439</u>	<u>\$ 256,799</u>	<u>\$ 194,875</u>
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			44,598 \$	15,822 \$	250,539 \$	447,599 \$	398,438 \$	(22,637) \$	(652,361) \$	42,377 \$	29,422 \$	6,813
Self-Insured Wk Cmp	92501832			200,000	250,000	527,244	175,000	175,000	(125,000)	0	0	0	0
				166,645	147,545	204,755	39,058	39,132	89,385	27,608	24,862	30,708	126,500
				<u>\$ 411,243</u>	<u>\$ 413,367</u>	<u>\$ 982,538</u>	<u>\$ 661,657</u>	<u>\$ 612,570</u>	<u>\$ (58,252)</u>	<u>\$ (624,754)</u>	<u>\$ 67,239</u>	<u>\$ 60,130</u>	<u>\$ 133,313</u>
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			102,387 \$	56,729 \$	187,477 \$	266,274 \$	255,486 \$	436,424 \$	230,435 \$	429,406 \$	127,267 \$	90,121
Self-Insured Wk Cmp	92501832			578,755	732,474	(317,925)	266,146	150,000	100,000	323,500	667,000	8,272	786,405
				65,891	434,794	160,412	108,369	117,616	278,340	57,624	126,298	67,246	93,819
				<u>\$ 747,033</u>	<u>\$ 1,223,997</u>	<u>\$ 29,964</u>	<u>\$ 640,789</u>	<u>\$ 523,102</u>	<u>\$ 814,764</u>	<u>\$ 611,559</u>	<u>\$ 1,222,703</u>	<u>\$ 202,786</u>	<u>\$ 970,345</u>
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			461,132 \$	861,634 \$	272,626 \$	120,945 \$	(50,247) \$	(26,922) \$	(64,610) \$	157,051 \$	(31,605) \$	637,558
Self-Insured Wk Cmp	92501832			500,000	(200,000)	0	100,000	200,000	(300,000)	275,000	10,367,500	200,000	(25,500)
Insurance	92501831			156,577	151,793	(35,421)	(12,115)	2,850	17,330	15,085	17,741	14,714	11,468
Allocation - Paluite	92501900			1,791,769	1,815,117	1,625,174	2,198,218	2,985,552	4,288,440	6,675,409	8,691,167	9,584,066	9,883,857
				<u>(157,863)</u>	<u>(254,979)</u>	<u>(109,694)</u>	<u>(137,202)</u>	<u>(180,260)</u>	<u>(204,911)</u>	<u>(317,404)</u>	<u>(803,610)</u>	<u>(255,113)</u>	<u>(430,803)</u>
				<u>\$ 2,751,815</u>	<u>\$ 2,373,565</u>	<u>\$ 1,752,685</u>	<u>\$ 2,269,846</u>	<u>\$ 2,957,895</u>	<u>\$ 3,773,937</u>	<u>\$ 6,583,480</u>	<u>\$ 18,429,849</u>	<u>\$ 9,512,061</u>	<u>\$ 10,076,580</u>
Total Account 925				<u>\$ 5,152,668</u>	<u>\$ 5,084,667</u>	<u>\$ 5,263,385</u>	<u>\$ 5,650,732</u>	<u>\$ 5,600,529</u>	<u>\$ 8,237,659</u>	<u>\$ 10,737,677</u>	<u>\$ 22,941,351</u>	<u>\$ 10,210,410</u>	<u>\$ 12,666,230</u>
Total Company													
Legal and Other Costs	92500001												
Reserve for Self-Insurance	92500001			875,275 \$	1,091,014 \$	1,586,951 \$	1,850,208 \$	1,398,308 \$	1,565,352 \$	985,630 \$	1,641,598 \$	819,790 \$	1,083,265
Self-Insured Wk Cmp	92501832			1,949,838	1,282,474	1,369,239	1,068,101	850,000	1,666,509	2,780,000	12,394,724	(767,268)	1,474,534
Insurance	92501831			693,449	1,151,041	791,715	671,407	546,929	922,269	614,042	1,017,473	828,935	655,377
Allocation - Paluite	92501900			1,791,769	1,815,117	1,625,174	2,198,218	2,985,552	4,288,440	6,675,409	8,691,167	9,584,066	9,883,857
				<u>(157,863)</u>	<u>(254,979)</u>	<u>(109,694)</u>	<u>(137,202)</u>	<u>(180,260)</u>	<u>(204,911)</u>	<u>(317,404)</u>	<u>(803,610)</u>	<u>(255,113)</u>	<u>(430,803)</u>
				<u>\$ 5,152,668</u>	<u>\$ 5,084,667</u>	<u>\$ 5,263,385</u>	<u>\$ 5,650,732</u>	<u>\$ 5,600,529</u>	<u>\$ 8,237,659</u>	<u>\$ 10,737,677</u>	<u>\$ 22,941,351</u>	<u>\$ 10,210,410</u>	<u>\$ 12,666,230</u>

**SOUTHWEST GAS CORPORATION
ARIZONA
RESPONSE TO STAFF DATA REQUEST NO. STF-6-60 AND D
ACCOUNT 228 RESERVE FOR SELF-INSURANCE
ACCOUNT BALANCE AND DEFERRED TAX**

<u>Month - Year</u>	<u>Account 228</u>	<u>Deferred Tax</u>	<u>Net</u>	<u>Arizona Allocation</u>
Four Factor				56.70%
April 30, 2006	\$ 13,356,643	\$ (5,279,747)	\$ 8,076,896	\$ 4,579,600
April 30, 2007	1,976,870	(781,437)	1,195,433	677,811
December 31, 2007	1,625,000	(642,346)	----- 982,654	--- --557,165

**SOUTHWEST GAS CORPORATION
ARIZONA
RESPONSE TO STAFF DATA REQUEST NO. STF-6-60 AND D
ACCOUNT 228 RESERVE FOR SELF-INSURANCE
ACCOUNT BALANCE AND DEFERRED TAX**

<u>Month - Year</u>	<u>Account 228</u>	<u>Deferred Tax</u>	<u>Net</u>	<u>Arizona Allocation</u>
Four Factor				56.70%
April 30, 2006	\$ 13,356,643	\$ (5,279,747)	\$ 8,076,896	4,579,600
April 30, 2007	1,976,870	(781,437)	1,195,433	677,811
November 30, 2007	2,425,000	(958,578)	1,466,422	831,461

295-026

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-10
(ACC-STF-10-1 THROUGH ACC-STF-10-26)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 29, 2008

Request No. ACC-STF-10-26: ✓

Aircraft and aviation operations. (a) Please identify the investment cost and operating cost of all owned and leased aircraft in the test year, and provide comparable information for calendar 2004, 2005, 2006 and 2007. (b) Please identify all costs and expenses, by account, for all owned and/or leased aircraft and aviation operations for the test year that were charged to Arizona utility operations.

Respondent: Revenue Requirements

Response:

Please find the attached schedule listing the operating costs associated with the leased aircraft used by Southwest for business operations. Southwest does not own any aircraft. The amounts are listed by account, from 2004 through 2007, as well as the test year, and the portion allocated to Arizona is shown. Any amounts that were directly charged to non-Arizona jurisdictions or below-the-line (Account 426.5) were excluded from this schedule.

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
DATA REQUEST NO. STF-10-26
LEASED AIRCRAFT OPERATING COSTS

Line No.	Account	2004	2005	2006	2007	Test Year TME 4/30/2007	Line No.
1	908.0	\$ -	\$ -	\$ -	\$ 1,500	\$ -	1
2	920.0	208,306	220,273	259,841	231,208	263,810	2
3	921.0	181,231	225,338	216,448	193,086	222,344	3
4	930.2	28,500	42,210	53,300	35,950	50,300	4
5	931.0	24,101	27,026	24,049	25,134	24,049	5
6	935.0	679	924	4,297	-	233	6
7	Total	\$ 442,816	\$ 515,771	\$ 557,935	\$ 486,878	\$ 560,736	7
Description							
8	Allocation to Palute Pipeline (PP)/SGTC	4.91%	4.91%	4.11%	4.12%	3.96%	8
9	Aircraft Expense Allocated to PP/SGTC	\$ 21,742	\$ 25,324	\$ 22,931	\$ 20,059	\$ 22,205	9
10	Aircraft Expense Net of PP/SGTC	\$ 421,074	\$ 490,447	\$ 535,003	\$ 466,819	\$ 538,531	10
11	AZ Allocation Factor	57.66%	57.10%	56.81%	56.78%	56.70%	11
12	Aircraft Expense Allocated to AZ	\$ 242,791	\$ 280,045	\$ 303,935	\$ 265,060	\$ 305,347	12

298-004

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 THROUGH ACC-STF-11-15)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 3, 2008

Request No. ACC-STF-11-4:

Amortizations. Refer to Southwest's W/P Schedule C-2, Sheet 89, Adjustment No. 14. For each item of new amortization listed in the following table, please provide the following information: (1) the actual cost, (2) the actual date placed into service, and (3) the documentation relied upon for the amortization period/service life:

New Amortizations beginning before 12/31/07

Description [1] (a)	Annual Amortization (b)	CWIP Balance @ 4/30/07 (c)	Estimated In-Service Date (d)	Estimated Asset Amount (e)	Service Life (f)
Autocad Map 3D 2007	\$ 60,000	\$ 125,879	6/30/2007	\$ 180,000	3 years
Pi Data Access	8,000	25,900	6/30/2007	24,000	3 years
Receivables Software	35,000	57,238	6/30/2007	105,000	3 years
Load Balancer	12,667	37,780	6/30/2007	38,000	3 years
MacKinney VS/Cobol License	3,500	10,420	6/30/2007	10,500	3 years
Citrix Presentation License	27,667	82,628	6/30/2007	83,000	3 years
San Lefthand Network Expansion	5,167	15,489	6/30/2007	15,500	3 years
EMRS/LMR Software Module	143,333	88,406	12/31/2007	430,000	3 years
EMRS Software	116,667	99,510	12/31/2007	350,000	3 years
Oracle UPK Licenses	83,333	0	12/31/2007	250,000	3 years
Oracle PUI Licenses	70,000	0	12/31/2007	210,000	3 years
Total New Amortizations	\$ 565,333	\$ 543,250		\$ 1,696,000	

Respondent: Revenue Requirements

Response:

Please see the attached worksheet for the actual in-service amounts and dates for the projects in the above table. The EMRS/LMR Module is still in CWIP.

(Continued on Page 2)

298-004
Page 2

Response to STF-11-4: (continued)

Generally, Southwest assigns a three-year service life to small software projects or software license purchases under \$1 million. This assignment is based on seasoned professional judgment, and there is no documentation Southwest relied upon to determine a service life for the above projects.

**SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
INTANGIBLE PLANT IN CWIP AT 4/30/07
ACTUAL COST AND IN-SERVICE DATE**

	Description [1] (a)	In-Service Date (b)	Asset Amount (c)	
1	Autocad Map 3D 2007	6/29/2007	\$ 128,129	1
2	Pi Data Access	6/27/2007	25,900	2
3	Receivables Software	6/29/2007	76,084	3
4	Load Balancer	5/24/2007	37,781	4
5	MacKinney VS/Cobol License	5/24/2007	10,149	5
6	Citrix Presentation License	5/24/2007	82,628	6
7	San Lefthand Network Expansion	5/24/2007	15,489	7
8	EMRS/LMR Software Module	N/A	[1]	8
9	EMRS Software	1/28/2008	195,120	9
10	Oracle UPK Licenses	12/17/2007	189,398	10
11	Oracle PUI Licenses	8/27/2007	172,400	11

[1] This project is still in CWIP.

993,078

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Attachment RCS-6
Copies of SWG's Confidential Responses to Data Requests
and Workpapers Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
Confidential Tax Memo	Income Tax Reserve Analysis	Yes	7	2 - 8
	Total Pages Including this Page		8	

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON

Chairman

WILLIAM A. MUNDELL

Commissioner

JEFF HATCH-MILLER

Commissioner

KRISTIN K. MAYES

Commissioner

GARY PIERCE

Commissioner

IN THE MATTER OF THE APPLICATION OF)
SOUTHWEST GAS CORPORATION)
FOR JUST AND REASONABLE)
RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF SOUTHWEST GAS)
CORPORATION DEVOTED TO ITS)
OPERATIONS THROUGHOUT ARIZONA.)

DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

CORKY HANSON

SENIOR PIPELINE SAFETY INSPECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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INTRODUCTION	1
ANALYSIS.....	2
RECOMMENDATIONS.....	5

**EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504**

The Direct Testimony of Staff witness Corky Hanson addresses the concerns of the Arizona Corporation Commission's ("Commission") Office of Pipeline Safety ("OPS" or "Pipeline Safety") relating to the Southwest Gas request to include replacement cost of the Manors subdivision gas distribution system in Yuma, Arizona.

Staff recommends the costs discussed in Staff witness Ralph Smith's testimony be disallowed from consideration in these proceedings because SWG's original intention was to extend the service life of the pipeline system by installing a new cathodic protection ground bed before incorrectly connecting the wires backwards on the rectifier causing the pipeline to corrode at an accelerated rate.

1 **INTRODUCTION**

2 **Q. Please state your name and business address?**

3 A. My name is Corky Hanson. My business address is 2200 N. Central Avenue, Phoenix,
4 Arizona.

5
6 **Q. What is your current position and how long have you been employed by the Arizona**
7 **Corporation Commission?**

8 A. I am a Senior Pipeline Safety Inspector; I have been employed by the Arizona Corporation
9 Commission ("Commission") for over 15 years.

10
11 **Q. Please describe briefly your duties as a Senior Pipeline Safety Inspector.**

12 A. Briefly, my duties include conducting annual pipeline safety inspections, conducting
13 investigations into the causes of pipeline failures, conducting pipeline construction
14 inspections, completing required reports associated with each inspection or investigation
15 and providing testimony on behalf of the Commission.

16
17 **Q. Have you previously testified?**

18 A. Yes, I have previously testified on behalf of the Commission.

19
20 **Q. What is the purpose of your testimony in these proceedings.**

21 A. The purpose of my testimony is to express the concerns Pipeline Safety has relating to the
22 cost and reasons for replacing the gas distribution system in the Manors subdivision
23 ("Manors") in Yuma.

24

1 **ANALYSIS**

2 **Q. Does the Pipeline Safety Section have any concerns with Southwest Gas Corporation**
3 **(“SWG” or “Southwest Gas”) that would effect this rate case?**

4 A. Yes, SWG is seeking to recover costs for the replacement in the Manors subdivision in
5 Yuma, Arizona steel pipeline gas distribution system. Pipeline Safety does not feel that
6 SWG should be able to recover these costs. The circumstances that necessitated the
7 immediate replacement of this system were the direct result of incorrect actions taken by
8 SWG personnel resulting in the failure of this system.

9
10 **Q. Explain the action taken by SWG personnel that caused the failure.**

11 A. During the SWG annual code compliance audit in 2006, it was noted on the inspection
12 report that SWG had not taken prompt remedial action to correct deficiencies of the
13 Manors cathodic protection (“CP”) identified during the annual CP monitoring. The CP
14 deficiency was identified on March 26, 2004. Remedial action was not completed until
15 February 28, 2006. Failure to provide adequate CP on a steel pipeline system can lead to
16 deterioration of the pipeline resulting in leaks and ultimately the replacement of the
17 pipeline. The technician responsible for making repairs to the CP rectifier system
18 connected the wiring backwards (positive to negative / negative to positive). This action
19 caused the pipeline to corrode at an accelerated rate resulting in multiple corrosion failures
20 and necessitating the immediate replacement of the steel pipeline system. SWG
21 management personnel did not identify this mistake until the system failed and required
22 replacement.

23

1 **Q. Briefly explain what cathodic protection is and its importance in protecting the**
2 **pipeline.**

3 A. Pipe corrosion is one of the leading causes of pipeline failures. CP is a procedure by
4 which an underground metallic pipe is protected against corrosion. A direct current is
5 impressed onto the pipe by means of either a sacrificial anode or a rectifier. CP
6 monitoring is conducted once each calendar year to ensure that minimum CP is being
7 maintained on the pipeline. The duration between inspections should not exceed 15
8 months.

9
10 **Q. Briefly explain what a rectifier is, how it operates and the consequences of improper**
11 **installation.**

12 A. A CP rectifier is a device that converts alternating current ("AC") into direct current
13 ("DC") for use with cathodic protection. The proper way to use a rectifier is to connect
14 the positive (+) wire terminal to the anode, and the negative (-) wire terminal to the
15 pipeline making the pipeline the cathode. In a properly installed system it is the anode
16 that loses current taking material with it until its mass is depleted thereby mitigating
17 corrosion on the cathode (pipeline). Reversing the wire connection (polarity) would cause
18 the pipe to become the anode, resulting in accelerated corrosion of the pipeline.
19 Southwest Gas claims that this rectifier was maintained and initialized by the same
20 Southwest Gas employee who was responsible for the Company's failure to conduct the
21 CP monitoring in 2006.

22
23 **Q. Based on your experience, could the Manors steel pipeline system have lasted for**
24 **many more years if adequate CP had been properly applied?**

25 A. Yes, based on my CP training and experience both as an operator and Pipeline Safety
26 Inspector, this system could have lasted for many more years. I also consulted with co-

1 workers Marion Garcia (Chemical Engineer) and Ryan Weight (Mechanical Engineer).
2 Both also have extensive cathodic protection experience, and both agree with my
3 assessment of this system. Pursuant to regulations, SWG had the option to either replace
4 the pipeline with plastic pipe (which does not require cathodic protection), or install CP.
5 Ground bed anodes on impressed current systems are normally designed to last, at a
6 minimum, 20 years. When SWG made the decision to replace the ground bed instead of
7 replacing the pipelines it was evident that the pipeline was in a condition that could be
8 preserved. Clearly, the intent was to extend the service life of the system. For SWG to
9 expend the cost and effort to replace the CP ground bed to restore CP to the Manors' steel
10 system, it is obvious that SWG planned on these actions extending the service life of this
11 system. Through only 11 months of operation using an incorrectly installed rectifier, the
12 pipeline was corroded to the point of being no longer operable. It is true that the pipeline
13 had been in service for 50 years. However, as SWG's service life extension efforts
14 demonstrate, there was no present need to replace the pipeline. SWG's actions are
15 consistent with Staff's belief that the pipeline had significant remaining life that could
16 have been extended with proper cathodic protection.

17
18 But for the improper repairs made by an SWG field technician, the Company would not be
19 incurring this expense. Customers should not have to pay for a new system when the
20 Company's own mistakes and improper repairs lead to the system's failure and need for
21 replacement.

22
23 **Q. Have you reviewed the list of 68 contracts provided by SWG to determine whether**
24 **the projects were used and are useful?**

25 **A. Yes.**
26

1 **Q. Does the Pipeline Safety Section have any additional concerns regarding the used**
2 **and useful analysis of the list of 68 contracts that would affect this rate case?**

3 A. No.
4

5 **RECOMMENDATIONS**

6 **Q. What is your recommendation in this case?**

7 A. I recommend that SWG be permanently disallowed from including the cost relating to the
8 Manors replacement project for consideration in this rate case and any future rate cases.
9 Staff witness Ralph Smith addresses the calculation of the disallowance in his testimony.
10

11 **Q. Does this conclude your Direct Testimony?**

12 A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON

Chairman

WILLIAM A. MUNDELL

Commissioner

JEFF HATCH-MILLER

Commissioner

KRISTIN K. MAYES

Commissioner

GARY PIERCE

Commissioner

IN THE MATTER OF THE APPLICATION OF)
SOUTHWEST GAS CORPORATION FOR THE)
ESTABLISHMENT OF JUST AND)
REASONABLE RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF SOUTHWEST GAS)
CORPORATION DEVOTED TO ITS)
OPERATIONS THROUGHOUT ARIZONA.)

DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

FRANK RADIGAN

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

My testimony addresses the Revenue Decoupling.

The Company proposes a full Revenue Decoupling Mechanism. Mr. Miller states that full Revenue Decoupling is reasonable for three reasons: 1) because it removes a major obstacle to promoting the goals of energy conservation and efficiency, 2) it is fair to the utility, its shareholders and its customers and 3) it is likely to reduce the burden on the Commission's regulatory resources, because greater earnings stability is likely to reduce the frequency of Southwest's rate cases.

There has been no showing in this case that the lack of Revenue Decoupling is a major obstacle to the promotion of energy efficiency. When the Company filed its DSM program in June 2006 it proposed to increase funding by 16 percent above prior levels.

There has also been no showing that Revenue Decoupling is fair to customers. While it is clear why the utility and its shareholders want to protect net income, ratepayers generally don't like clauses that are designed to automatically increase their bills.

The argument that the Company will be able to reduce the frequency of rate cases is unimpressive. The Company last raised rates in April 2006 by just under \$50 million per year. In this case the Company is asking to increase rate by another \$50 million with the single largest factor being identified as the cost of capital – over \$20 million. Any effect of decreased margin due to energy conservation is dwarfed by other factors impacting the Company's financial position.

Contrary to the Company claim that Revenue Decoupling has broad support, while it is true that NARUC endorses the idea that State Commissions should review and consider decoupling, NARUC has also advised caution. In its September 2007 FAQ sheet on decoupling NARUC states that "Decoupling is a substantial departure from traditional rate-making, and may be new to States and utilities. Therefore it makes sense to approach implementation with caution, considering corrective mechanisms to ensure that the change in structure has the intended effects and avoids harmful unintended consequences."

As to the efforts of other States, decoupling has had a varied past. States like Washington, Maine and New York adopted decoupling and then dropped it. While the Company notes that Washington Gas Light has full revenue decoupling in Maryland, the utility proposed the idea in its rate case in the District of Columbia, parties opposed it and the Company withdrew the proposal in a settlement of the rate case.

The Company's proposal also lacks of stakeholder support. In Decision No 68487 the Commission directed the Company to coordinate its efforts with all affected stakeholders. From that process RUCO has filed comments that the meetings proved useful in that the parties were

able to identify weather as the true cause of SWG's inability to recover at approved levels, and the conservation efforts are of relatively little significance to the under-recovery phenomenon.

The Company should not be permitted to ignore the outcome of the collaborative process in this rate case. If they actually had a case to make they should have presented it to stakeholders and gotten their support. The Company has failed in its burden of proof that decoupling is necessary or will work to achieve the goal of promoting energy efficiency.

1 **INTRODUCTION**

2 **Q. Please state your name, occupation, and business address.**

3 A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a
4 consulting firm providing services regarding the electric utility industry and specializing
5 in the fields of rates, planning and utility economics. My office address is 120
6 Washington Avenue, Albany, New York 12210.

7
8 **Q. Please describe your educational background and professional experience.**

9 A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College
10 of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a
11 Certificate in Regulatory Economics from the State University of New York at Albany in
12 1990. From 1981 through February 1997, I served on the Staff of the New York State
13 Department of Public Service ("DPS") in the Rates and System Planning sections of the
14 Power Division. My responsibilities included resource planning and the analysis of rates,
15 depreciation rates and tariffs of electric, gas, water and steam utilities in the State. They
16 also encompassed rate design and performing embedded and marginal cost of service
17 studies as well as depreciation studies.

18
19 Before leaving the DPS, I was responsible for directing all engineering staff during major
20 proceedings including those relating to rates, integrated resource planning and
21 environmental impact studies. In February 1997, I left the DPS and joined a firm called
22 Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed
23 my own Company. In my 27 years of experience, I have testified as an expert witness in
24 utility rate proceedings on more than 60 occasions before various utility regulatory bodies,
25 including this Commission, the Nevada Public Utility Commission, the New York State
26 Department of Taxation and Finance, the New York State Public Service Commission, the

1 Connecticut Department of Utility Control, the Rhode Island Public Utilities Commission,
2 the Michigan Public Service Commission, the Vermont Public Service Board and the
3 Federal Energy Regulatory Commission.

4
5 **Q. Have you prepared an attachment summarizing your educational background and**
6 **regulatory experience?**

7 A. Yes. Attachment FWR-1 provides details concerning my experience and qualifications.
8

9 **Q. On whose behalf are you appearing?**

10 A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or
11 "Commission") Utilities Division Staff ("Staff").
12

13 **REVENUE DECOUPLING**

14 **Q. What is the scope of your testimony in this case?**

15 A. I will address the Company's presentation of full Revenue Decoupling as presented by
16 Company Witnesses Ralph Miller and A. Brooks Congdon.
17

18 **Q. What is the Company proposing in this case?**

19 A. In Southwest Gas Corporation's ("SWG" or the "Company") the last case, Docket No. G-
20 01155A-04-0876, the Company proposed a Conservation Margin Tracker to address the
21 Company's ongoing inability to achieve its authorized rate of return due, at least in part, to
22 declining per customer usage on its system. In that case, Decision No. 68487, the
23 Commission found that there was conflicting evidence in the record as to whether the
24 declining usage will continue and whether conservation efforts are the direct cause of
25 Southwest Gas' inability to earn its authorized return. In this case, Company witness A.
26 Brooks Congdon states that Decision No. 68487 did contain several references to the need

1 to promote maximum energy efficiency. Based on these references, he concludes the
2 Commission is clearly committed to protecting energy supplies for future Arizona
3 generations (Congdon, page 4). Company Witness Ralph Miller recommends the
4 adoption of full Revenue Decoupling for Southwest's residential customers and all but its
5 largest general service customers. (Miller, page 4).

6
7 Mr. Miller states that Revenue Decoupling is a rate design alternative to traditional rate
8 design. Under traditional rate designs, he states that a large fraction of a utility's non-gas
9 cost recovery is achieved through volumetric rate components. Revenue Decoupling
10 breaks or weakens this linkage between a gas utility's non-gas revenues and its volumetric
11 sales or total throughput. Full Revenue Decoupling eliminates the linkage completely.
12 Partial decoupling weakens the linkage but does not eliminate it. (Miller, page 2). The
13 proposed Revenue Decoupling Adjustment Provision ("RDAP") and Weather
14 Normalization Adjustment Provision ("WNAP") together accomplish full Revenue
15 Decoupling. (Miller, page 4)

16
17 **Q. Please explain the proposed WNAP?**

18 A. In SWG's proposed weather normalization provision, the adjustment is made each month
19 to reflect the difference between actual and normal weather in that month (Miller, p. 10).
20 Company witness Miller states that this timing is similar to SWG's current system of
21 making small changes to the monthly gas cost, which has proven acceptable to customers.
22 Company witness Miller argues that weather normalization benefits the Company because
23 it eliminates the fluctuations in non-gas revenue that would otherwise occur whenever the
24 actual weather is colder or warmer than the normal weather used for the test year to design
25 the utility's rates. SWG also argues that a weather normalization provision is a benefit to
26 ratepayers. SWG argues that weather normalization moderates the fluctuation in the

1 customer's bill that occurs when weather is colder than normal and when it is warmer than
2 normal. Under the proposal, in colder than normal months, the customer's bill increases
3 less than it would under a traditional rate design, and in warmer than normal months, it
4 decreases less than it would under a traditional rate design.

5
6 **Q. Please explain the proposed Revenue Decoupling Adjustment Provision ("RDAP")?**

7 A. The RDAP is styled after a mechanism recently approved by the Public Service
8 Commission of Utah for Questar Gas Company (Congdon, page 7). The proposed RDAP
9 provides for recovery of non-weather related dollar differences between actual and
10 authorized non-gas revenue by recording monthly differences in non-gas revenue per
11 customer in a deferred account and recovering the balance annually through a rate
12 adjustment (surcharge). The Company claims that the process is identical in nature to the
13 accounting for Southwest's Purchased Gas Cost Adjustment Provision (Congdon, page 5).

14
15 **Q. What is the Company's reasoning for proposing full Revenue Decoupling?**

16 A. The Company states that consideration of the promotion of the goal of energy efficiency
17 in the regulatory process is important because utilities are in a position to influence energy
18 usage decisions, which affect energy conservation and efficiency. The Company states
19 that utilities can promote the energy efficiency goal through advertising, through
20 promotional programs, and through other activities too closely tied to the provision of
21 utility services to be conducted independently by third parties. SWG states that regulators
22 seeking to promote energy conservation and efficiency should establish regulatory policies
23 that encourage utilities to support the achievement of these goals. SWG argues that
24 traditional rate designs are adverse to energy conservation and efficiency because they
25 impose a financial penalty on gas utilities whenever usage per customer decreases. Thus
26 they create a financial disincentive for the utility to support any program that reduces

1 customer usage, even if that program is an efficient use of resources for the economy as a
2 whole (Miller, page 8).

3
4 Mr. Miller states that full Revenue Decoupling is reasonable for three reasons: 1) because
5 it removes a major obstacle to promoting the goals of energy conservation and efficiency,
6 2) it is fair to the utility, its shareholders and its customers and 3) it is likely to reduce the
7 burden on the Commission's regulatory resources, because greater earnings stability is
8 likely to reduce the frequency of Southwest's rate cases (Miller, page 4).

9
10 **Q. Do you agree with these reasons?**

11 A. No. While proponents of energy conservation efforts want to remove as many obstacles
12 as possible, there have been no showing in this case that the lack of Revenue Decoupling
13 is a major obstacle to the promotion of energy efficiency. When the Company filed its
14 DSM program in June 2006 it proposed to increase funding 16 percent above prior levels.
15 There has also been no showing that Revenue Decoupling is fair to customers. While it is
16 clear why the utility and its shareholders want to protect net income, ratepayers generally
17 don't like clauses that are designed to automatically increase their bills. Finally, the
18 argument that the Company will be able to reduce the frequency of rate cases is
19 unimpressive. The Company last raised rates in April 2006 by just under \$50 million per
20 year. In this case the Company is asking to increase rate by another \$50 million with the
21 single largest factor being identified as the cost of capital -- over \$20 million. Any effect
22 of decreased margin due to energy conservation is dwarfed by other factors impacting the
23 Company's financial position.
24

1 **Q. Does the Company have any other reasons for proposing full Revenue Decoupling?**

2 A. Yes, the Company claims that traditional rate designs hamper a company's ability to
3 recover its authorized cost per customer because non-gas revenues vary with weather-
4 related and other changes in use per customer. Traditional rate designs also penalize
5 utilities for promoting economically efficient conservation. According to the Company
6 full Revenue Decoupling is important because it solves these problems. It promotes a
7 utility's financial health, while allowing the utility to aggressively promote economically
8 efficient conservation with no attendant financial harm (Miller, page 3).

9
10 **Q. Do you agree with this reason?**

11 A. No. This is an argument that a rate design with a volumetric component adds risk to the
12 Company's ability to earn its net income because usage can vary with weather, and the
13 Company has been vociferous on this subject. In its 2007 10-K filing with the Securities
14 Exchange Commission the Company stated "Weather is a significant driver of natural gas
15 volumes used by residential and small commercial customers and is the main reason for
16 volatility in margin. Space heating-related volumes are the primary component of billings
17 for these customer classes and are concentrated in the months of November to April for
18 the majority of the Company's customers. Variances in temperatures from normal levels,
19 especially in Arizona where rates remain leveraged, have a significant impact on the
20 margin and associated net income of the Company. Differences in heating demand,
21 caused primarily by weather variations between 2006 and 2005, accounted for a \$3
22 million increase in operating margin." In its 2007 Annual Report to shareholders, the
23 Company reported "Unfortunately, we were disappointed that the ACC did not approve
24 the key rate design proposals the Company made to mitigate the effects of weather
25 volatility and customer conservation resulting from higher natural gas prices and more
26 efficient building standards in new construction. And while the weather improved over

1 the prior year, it was still warmer than normal and, consequently, our operating margin in
2 Arizona was negatively impacted.”

3
4 **Q. Does the Company have any other justification for Revenue Decoupling?**

5 A. Yes, company Witness Ralph Miller states that Revenue Decoupling has broad support.
6 He notes that the traditional use of volumetric rates to recover fixed costs that are
7 independent of sales volume has been an issue for many years. Mr. Miller points to
8 FERC’s adoption of a straight fixed-variable (“SFV”) method of rate design for interstate
9 pipelines in its Order 636 in April 1992. Within the past few years, Mr. Miller states that
10 there has been intense interest in full Revenue Decoupling for gas distribution utilities.

11
12 Mr. Miller points to a Joint Statement of the American Gas Association (“AGA”) and the
13 Natural Resources Defense Council (“NRDC”), which the AGA and NRDC submitted to
14 NARUC in July 2004 (“the Joint Statement”). The Joint Statement explained that
15 traditional volumetric rates are a "significant financial disincentive for natural gas utilities
16 to aggressively encourage their customers to use less gas", and it supported "mechanisms
17 that use modest automatic rate true-ups to ensure that a utility's opportunity to recover
18 authorized fixed costs is not held hostage to fluctuations in retail gas sales." The Joint
19 Statement was submitted as Exhibit 1 to the pre-filed testimony of Ralph Miller.

20
21 Mr. Miller also points to a Resolution on Gas and Electric Energy Efficiency, adopted by
22 the NARUC Board of Directors on July 14, 2004. SWG notes that the NARUC Board
23 encourages State Commissions to review and consider the recommendations in the Joint
24 Statement. The resolution was submitted as Exhibit 2 to the pre-filed testimony of Ralph
25 Miller.

26

1 Mr. Miller also notes that certain states have supported decoupling. SWG points to the
2 fact that Nevada adopted legislation to permit Revenue Decoupling. The Company notes
3 that Maryland adopted full Revenue Decoupling for its two large gas utilities, Baltimore
4 Gas and Electric Company and Washington Gas Light Company and that California did it
5 more than 20 years ago. Company witness Miller testified that among the states with full
6 or essentially full Revenue Decoupling linked to conservation programs are Oregon, New
7 Jersey, Missouri and Utah. Mr. Miller also noted that Colorado, Indiana, Ohio, and
8 Washington each adopted at least partial decoupling sometimes on a pilot or test basis. He
9 also notes that a few states, including North Dakota and Georgia, have allowed full
10 decoupling in the form of SFV rate designs (Miller, page 6).

11
12 **Q. Do you agree that there is broad support for full Revenue Decoupling?**

13 **A.** No. First, while it is true that NARUC endorses the idea that State Commissions should
14 review and consider decoupling, NARUC has also advised caution. In its September 2007
15 FAQ sheet on decoupling NARUC states that "Decoupling is a substantial departure from
16 traditional rate-making, and may be new to States and utilities. Therefore it makes sense
17 to approach implementation with caution, considering corrective mechanisms to ensure
18 that the change in structure has the intended effects and avoids harmful unintended
19 consequences." I have attached the FAQ sheet as Exhibit FWR-2.

20
21 As to the efforts of other States, decoupling has had a varied past. States like Washington,
22 Maine and New York adopted decoupling and then dropped it. Maine pioneered a fully
23 Decoupled rate design with Central Maine Power in 1991 but faced a recession in the
24 early 1990s. The sudden and sharp downturn in the Maine economy reduced consumption
25 to a much greater degree than the utility's efficiency efforts and the recession resulted in
26 lower electricity sales. The Decoupling adjustment adjusted rates to reflect pre-recession

1 target revenues and the adjustments caused rates to go up. Rather than promoting
2 conservation decoupling became to be viewed as a mechanism that was shifting the
3 economic impact of the recession from the utility to consumers. By 1993, deferrals
4 accumulated to such a high level that the Maine Commission and the utility agreed to end
5 the experiment.

6
7 In 1995, the Washington Utilities and Transportation Commission ("UTC") decided to
8 terminate its experimental periodic rate adjustment mechanism ("PRAM") for Puget
9 Sound Power & Light, Co. The mechanism was designed to remove disincentives to
10 conservation by decoupling revenues from sales levels and allowing dollar-for-dollar
11 recovery of resource-acquisition costs. The UTC found that in the 5 years of experience
12 with the PRAM, there were increases in rates in every year and the increases resulted from
13 an extraordinary combination of events: 1) the addition of new power sources, 2) extended
14 drought conditions in the Columbia basin, 3) warmer than average winters, and (4) Puget's
15 initiation of an aggressive conservation program. Under the PRAM's "awkward
16 marriage," the rate impacts of the resource-cost adjustment overwhelmed the rate impacts
17 of the decoupling adjustment, making a fair comparison of decoupling with traditional
18 ratemaking difficult. The UTC added that neither feature provided a clear incentive for
19 the company to manage its acquisition of supply- and demand-side resources at least cost,
20 and that the PRAM shifted some degree of risk from the company to its customers.
21 Washington Utilities and Transportation Commission v. Puget Sound Power & Light Co.,
22 Docket No. UE-950618, Sept. 21, 1995 (Wash.U.T.C.).
23

1 **Q. Does rejection of full or partial Revenue Decoupling mean that you do not support**
2 **energy conservation?**

3 A. No, but I share the concerns that the Commission had in SWG's last rate case. First, the
4 issue should be fully explored as part of a broader investigation of usage volatility and
5 margin recovery. The Commission also wanted evidence that declining customer usage
6 would continue, to what level and whether conservation efforts are the cause. No
7 evidence on either of these issues was presented in this case. No evidence was provided
8 that showed that the Company needs "full Revenue Decoupling". Other than the
9 administrative ease of implementing decoupling on a revenue per customer basis, I see no
10 link between weather normalization and energy conservation. And as I noted above, it
11 appears that what the Company really wants is protection from the weather. When one
12 looks at the options for partial decoupling, one must have evidence of what the monetary
13 losses are that are attributable to energy conservation efforts. No substantive evidence has
14 been presented here. Nor has any evidence been provided as to whether most of the
15 potential losses could be eliminated by just adopting simple rate design changes such a
16 increasing the customer charge.

17
18 One last reason for rejecting the Company's proposal is lack of stakeholder support. In
19 Decision No 68487 the Commission directed the Company to coordinate its efforts with
20 all affected stakeholders. Company witness Congdon testified that in developing its
21 proposal the Company considered the Commission's concerns and the opinions expressed
22 at the rate design collaborative (Congdon, page 4).

23
24 Considering concerns and opinions is not the same as building a broad-based proposal that
25 could be supported by all affected stakeholders. The Company needs to recognize that
26 decoupling is a substantial departure from traditional rate making and any change will

1 require a true showing of need, rate impacts, customer education, and broad based support.
2 The Company has not shown that it has even done that. On July 26, 2007 the Residential
3 Utility Consumer Office ("RUCO") filed comments on the outcome of the collaborative.
4 As noted in the RUCO comments "No consensus was ultimately reached between the
5 parties on these more relevant topics. However, the meetings proved useful in that the
6 parties were able to identify weather as the true cause of SWG's inability to recover at
7 approved levels, and the conservation efforts are of relatively little significance to the
8 under-recovery phenomenon." (Docket No. G-01551A-04-0876, July 26, 2007 filing).

9
10 Another factor that came out of the collaborative is the fact that SWG's losses in margin
11 recovery due to energy conservation are relatively small in proportion to the impacts of
12 other factors, such as weather. Over three years SWG has under recovered its margin by
13 \$22.5 million. Of this amount, \$4.5 million, or approximately 20 percent was due to
14 conservation, and \$18.1 million, or 80 percent, was attributable to weather (Ibid). This is
15 logical given the gas usage by ratepayers in southern Arizona. With relatively low per-
16 customer total usage, the losses from conservation will also likely be small.

17
18 The Company should not be permitted to ignore the outcome of the collaborative process
19 in this rate case. If they actually had a case to make, they should have presented it to
20 stakeholders and gotten their support. The Company has failed in its burden of proof that
21 decoupling is necessary or will work to achieve the goal of promoting energy efficiency.

22 23 SUMMARY OF RECOMMENDATIONS

24 **Q. Could you please summarize your testimony?**

25 A. The Company has three mains reasons for proposing a full Revenue Decoupling
26 Mechanism: 1) it removes an obstacle to promoting energy conservation 2) it is fair to the

1 utility, its shareholders and its customers and 3) it will reduce the frequency of rate cases.
2 None of the Company's reasons are persuasive and the Company has failed its burden of
3 proof. There has been no showing in this case that the lack of Revenue Decoupling is a
4 major obstacle to the promotion of energy efficiency. There has also been no showing
5 that Revenue Decoupling is fair to customers. Finally, the argument that the Company
6 will be able to reduce the frequency of rate cases is unpersuasive. The Company last
7 raised rates in April 2006 by just under \$50 million per year. In this case the Company is
8 asking to increase rate by another \$50 million with the single largest factor being
9 identified as the cost of capital – over \$20 million. Any effect of decrease margin due to
10 energy conservation is dwarfed by other factors impacting the Company's financial
11 position.
12

13 **Q. Does this conclude your Direct Testimony?**

14 **A.** Yes it does.

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present Principal, Hudson River Energy Group, Albany, NY -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 Manager Energy Planning, Louis Berger & Associates, Albany, NY -- Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 Senior Valuation Engineer, New York State Public Service Commission, Albany, NY -- Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies. Wholesale power system modeling with GE-MAPS.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning -- Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool -- the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing -- Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis -- Confidential client -- Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by \$700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 07-M-0906 – Energy East and Iberdola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over \$1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the

reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design and its for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities

Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* -- On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England.

Docket No. 03-10002 -- Nevada Power Company -- On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 -- Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners -- Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 -- Narragansett Electric -- Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 -- Connecticut Light and Power Company -- Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 -- Boston Edison Company -- Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 -- Corning Incorporated -- Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 -- Nucor Steel Auburn, Inc. -- Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 -- Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 -- New York State Electric and Gas Corporation -- Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 -- On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 -- Consolidated Edison: Electric Rate Restructuring -- On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 -- Petition of New York State Electric & Gas -- Multi-Year Electric Price Protection Plan -- Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 -- Joint Petition of Co-Owners of Nine Mile Nuclear Station -- Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed \$4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed \$0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of \$400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates.

1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

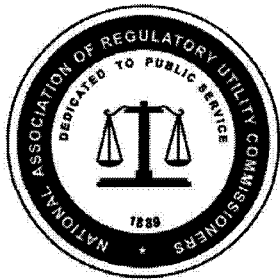
IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association, Northeast Public Power Association and New York State ISO.

2007



NARUC

**The National
Association
of Regulatory
Utility
Commissioners**

**Decoupling For Electric & Gas
Utilities:
Frequently Asked Questions
(FAQ)**

Grants & Research Department
September 2007

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Introduction

State Public Utility Commissions around the country are expressing increasing interest in energy efficiency as an energy resource. However, traditional regulation may lead to unintended disincentives for the utility promotion of end-use efficiency because revenues are directly tied to the throughput of electricity and gas sold. To counter this “throughput disincentive,” a number of States are considering alternative approaches intended to align their utilities’ financial interests with the delivery of cost-effective energy efficiency programs. “Decoupling” is a term more are hearing as a mechanism that may remove throughput disincentives for utilities to promote energy efficiency without adversely affecting their revenues.

In its July 14, 2004, resolution supporting efficiency for gas and electric utilities, the National Association of Regulatory Utility Commissioners (NARUC) resolved “to address regulatory incentives to address inefficient use of gas and electricity” (NARUC, 2004). In doing so, NARUC found that regulators are confronted with questions about what ratemaking mechanisms would be most effective in achieving commission objectives, satisfying the needs of utilities, and providing the greatest benefit to ratepayers. Decoupling represents a departure from common regulatory practice, and States that are considering decoupling should approach this with appropriate care. **For States considering decoupling, this paper is intended to provide an introduction and answer some of the most frequently asked questions, and to help determine if and how decoupling might be used.**

1. What is decoupling? In the electricity and gas sectors, “decoupling” (or “revenue decoupling”) is a generic term for a rate adjustment mechanism that **separates (decouples) an electric or gas utility’s fixed cost¹ recovery from the amount of electricity or gas it sells.** Under decoupling, utilities collect revenues based on the regulatory determined revenue requirement, most often on a per customer basis. On a periodic basis revenues are “trued-up” to the predetermined revenue requirement using an automatic rate adjustment.

The result is that **the actual utility revenues should more closely track its projected revenue requirements, and should not increase or decrease with changes in sales.** Since utilities will be protected if their sales decline because of efficiency, proponents of decoupling contend that they are more likely to invest in this resource, or may be less likely to resist deployment of otherwise economically beneficial efficiency.² Decoupling is also being explored in the water utility sector, though this paper focuses on the electricity and natural gas sectors.

2. How does decoupling work? Decoupling begins with the same rate case process as current regulatory models use, so it is useful to review traditional ratemaking to understand how decoupling works.

How are rates are set under traditional regulation? With traditional regulation, the rates utilities can charge are determined in a **rate case**, using the “**cost of service**” **theory of regulation**.³ Rates are set at a

¹ For our purposes “fixed costs” are those costs incurred to render service, which remain relatively constant between rate cases. These typically include investment costs, including interest on debt and return on equity, and unavoidable maintenance costs for power plants, transmission lines, gas pipelines, and other infrastructure, as well as employee payroll. Variable costs are those which vary with the level of electric or gas output and include fuel expenses, purchased power, and costs that vary broadly from month to month and are not included in decoupling mechanisms. These are often addressed through fuel or other adjustment clauses under existing regulatory practice.

² Decoupling advocates note that it removes a financial disincentive to energy efficiency, but may not create an incentive. Some decoupling advocates also argue that decoupling can help remove barriers to the integration of demand response and distributed resources.

³ Why are utilities prices set by regulation and based on their cost of service? Electricity and natural gas are considered to be essential services, and it is in the interest of society to ensure that the businesses that provide these services can pay for the costs of their operations and capital. Because these services are provided by

level sufficient to allow the utility to recover costs incurred in providing service to its customers based on the operating experience of a typical 12 month period (referred to as a “test year”). Test year expenses include the commission-determined or -allowed rate of return on investments. The utility’s **revenue requirement** is determined by adding the total of these expenses and the allowed return on investment. The revenue requirement is divided by the amount of sales in the test year to derive throughput based rates. In a rate case, test-year sales and operating costs are typically adjusted to reflect “normal” weather. This can be based on a model of future years, or it can be based on past years: test years based on forecasted experience are known as future test years, while test years based on prior financial performance are referred to as historical test years. Regardless of the type of test year used, the resulting prices are what customers pay per unit of electricity or gas that they use until rates are reset with next rate case.

How does traditional rate regulation create a throughput incentive? While prices are based on test year information, after a rate case actual sales will almost always differ because the exact patterns of customer use are complex to predict: weather, changes in the economy, demographic shifts, new end-use technologies, additions or reductions in the number of customers, and many other factors can affect actual sales. As a result, it is highly likely that the utility will sell more or less electricity or gas than had been assumed for the test year during the rate case. However, fixed costs are likely to be predictable. In the energy sector, the cost of service tends to have a large component of fixed costs associated with investments like power plants, gas pipelines, and electric transmission lines. This makes it difficult, but not impossible, for the utility to increase profits by cutting costs⁴. Revenues are much easier to increase, which means that utilities have a strong incentive to increase revenues by increasing sales. For existing customers, sales growth may not require a great deal of new infrastructure and in these cases, the utility’s fixed costs would not go up with increased sales⁵. In these cases, increases in sales volumes translate into increased revenues which in turn directly lead into increased profits. **In fact, some observers have noted that because of the link between profits and sales, a 1% increase in sales might lead to a 5% increase in profits (with corresponding decreases in profits when efficiency reduces sales)** (Harrington, 2007, 1994). Because the utility makes more money and profit by selling more electricity or gas, this structure could theoretically create a significant **disincentive for utilities to encourage their customers to lower consumption through energy efficiency**.

3. How is decoupling different? Decoupling does not change the traditional rate case procedure but, in its simplest form, adds an automatic “true-up” mechanism that adjusts rates between rate cases based upon the over- or under-recovery of target revenues. As in the traditional rate case, a rate is set by determining the revenue requirement and dividing it by expected sales⁶. Then, on a regular basis, prices are re-computed to

monopoly utilities, customers could be vulnerable to price exploitation. As a result, for over a century, prices have been regulated by State PUCs to recover the utilities’ costs, while utilities have assumed an obligation to provide service to the public.

⁴ What about variable costs? Even though utilities’ fixed costs are high, they also see fluctuations in variable items such as purchased power and the cost of fuels like coal or natural gas. These items are, in part, covered in the rate set in a rate case, but unexpected costs are also covered through surcharges that are temporary in nature and do not involve going through a whole rate case. Fuel Adjustment Clauses are an important variable cost that is passed through directly to customers in most states. Decoupling is not applied to these variable components.

⁵ For new customers, infrastructure costs may reflect regional patterns. In some regions of the country, adding new customers may require high additional infrastructure costs: connecting a building full of new gas customers in the urban areas of the Northeast may require a short new addition of pipe in an area with an existing distribution system. In other areas, adding new customers means adding costly new infrastructure, such as building long system additions to provide new gas service to rapidly-growing areas of the Southwest.

⁶ In decoupling’s simplest form, prices are adjusted to maintain a constant target revenue; however, in most applications of decoupling the target revenue is adjusted for changes in the customer base so that the revenue target varies with the number of customers, but not on the basis of how much electricity or gas the utility sells.

collect a target revenue based on actual sales volumes⁷. Decoupling mechanisms can be designed to be adjusted on a monthly or quarterly basis, or some other regular interval.

The end result is that utilities should no longer have an incentive to maximize their sales because the rate of return does not change within the revenue requirement. Nor is there a disincentive to promote efficiency.

Decoupling should have the effect of stabilizing the revenue stream of a utility because its revenues are no longer dependent on sales. If sales increase, rates drop in the next period; if sales decrease, rates increase to compensate. Under traditional rate regulation, there is little oversight of earnings between rate cases, and it may be years before rates are realigned with actual revenue requirements. Since decoupling adjusts actual revenues to align them with revenue requirements, its proponents argue that it **reduces regulatory lag**.

A hypothetical example of how decoupling might work:

During its rate case, Utility A determines it will have a \$1 million revenue requirement to provide electricity service 25 million kilowatt hours (kWh) of electricity in a test year. Under the existing system, this means Utility A will charge \$.04 per kWh¹.

If a successful energy efficiency program helped customers reduce overall consumption in by 1.5%, the utility would sell 375,000 fewer kWh, and its revenues would decline by \$15,000. Under decoupling, prices would be adjusted to \$.0406 per kWh to maintain the \$1 million dollar allowed revenue recovery.

If a customer's rate goes up, their bill won't necessarily follow, as will be discussed later in the FAQ: the bill-reduction benefits of consuming less significantly outweigh the reduction in those benefits that is caused by rates being adjusted.

4. What is the relationship between decoupling and incentives for energy efficiency?

If utilities are required to promote energy efficiency programs, their revenues may be affected through a variety of mechanisms. Commissions can address these new costs by providing program cost recovery and shareholder incentives, as well as by addressing the throughput issue.

A great deal has been written about incentives for energy efficiency, which is a related but different discussion. **While it can remove disincentives for utilities to promote efficiency, decoupling is not designed to create an incentive for energy efficiency.** Furthermore, as discussed above, there are other methods that remove the throughput disincentive, although revenue decoupling may best balance the removal of utility disincentives to energy efficiency while preserving customer incentives to deploy energy efficiency.

Some decoupling proponents have argued that removing disincentives is not enough. They contend that the cost of efficiency programs should be included as part of the cost of service. Moreover, in order to make efficiency investments profitable when compared to other possible investments that the utility could make, such as power plants or transmission, performance incentives for efficiency would reward utilities that invest in successful programs by allowing them to earn an equivalent rate of return on those investments. **Conversely, some argue that incentives alone, without decoupling, are a better approach to driving energy efficiency.** They note that many utilities are doing little to promote additional sales of electricity and the increases are customer-driven. Furthermore, some who have investigated decoupling note that in many cases utility spending on efficiency is already effective, cost-effective and well-managed. (Connecticut DPUC, 2006, NASUCA 2007 Resolution). In addition, large customers have argued that they may already possess the means and incentives to enact energy efficiency measures, and that decoupling does little to create new opportunities for efficiency in these markets (ELCON 2006).

⁷ The target revenue can be the same as that used in the last rate case, or it too can be adjusted over time by increasing or decreasing the average revenue per customer value. More information on alternatives to the Per-Customer method is included later in the FAQ.

Finally, some argue that utilities are not the best providers of energy efficiency. In this argument, utilities are organizations designed to deliver kilowatt hours and therms to their customers, and are ill-suited to champion products that “unsell” electricity or gas. Arguments have been made that taking utilities out of the efficiency businesses and having that function played by a State, quasi-State, or private sector entity is a preferable alternative to removing disincentives to their promoting efficiency (ELCON, 2006). In fact, numerous examples exist of successful efficiency programs being delivered by non-utility providers. However, some make the case that if utilities are required to examine efficiency as a resource comparable to supply (generation) and delivery (transmission) resources, this may create a perverse tension between the utility’s least-cost resource planning processes and the financial interest of its shareholders (Costello, 2006). **In situations where the utility is recast as a provider of energy services, rather than a strict provider of kilowatt hours or therms, decoupling may help remove this tension** (Costello 2006, NAEPE, 2006).

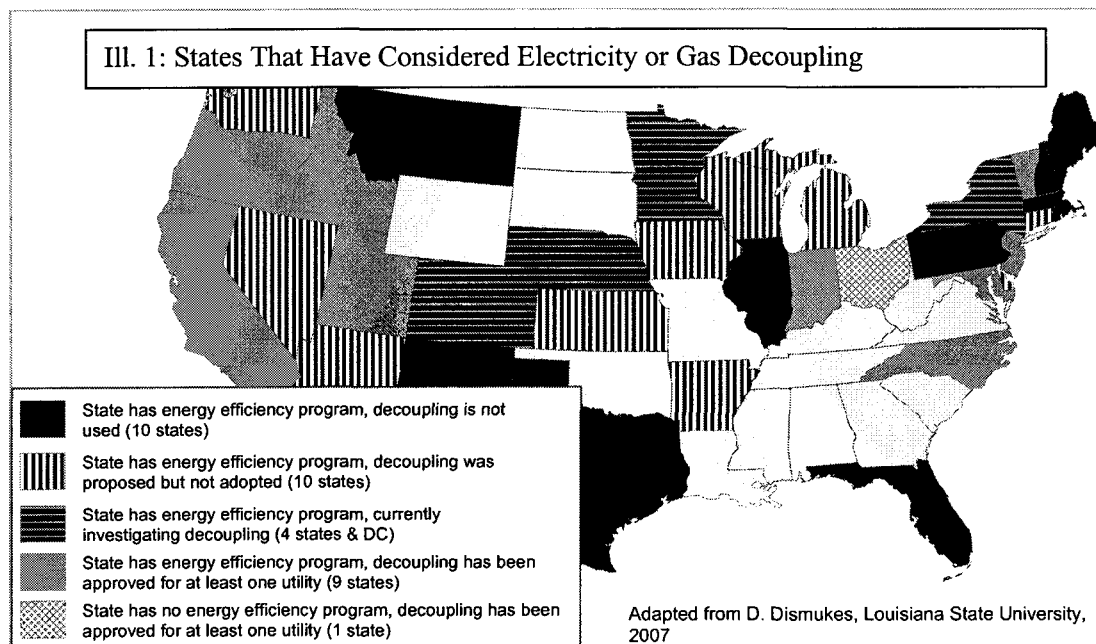
Some proponents of decoupling also note that even if a the utility is taken out of the efficiency business and that function is played by a State, quasi-State, or the private sector, the problem of the effect of decreased sales on utility revenues due to energy efficiency and the consequent decreased likelihood of the utility receiving its authorized revenue requirement does not go away. In this argument, even if other entities are responsible for providing energy efficiency services, the same need for decoupling still exists.

Whether decoupling will in itself result in increased efficiency is still the subject of debate. While no major studies have been undertaken linking decoupling directly to increased efficiency activities at utilities, anecdotally energy efficiency advocates point to strong increases in efficiency spending concurrent with decoupling undertaken by utilities, in particular in the electricity sector, with examples such as Puget Energy and PacifiCorp increasing activity and spending under decoupling and experiencing drop-offs in efficiency spending when decoupling was rescinded (NRDC, 2001). However, a closer look at Consolidated Edison’s efficiency spending while using decoupling (1993-1997) tells a different story: in this time period, efficiency spending increased by all the regulated utilities in New York, whether they used decoupling or not.

Decoupling is one of three major approaches for dealing with the throughput issue:

- 1. Full or Per-Customer Adjustment Revenue Decoupling.** This is the mechanism that has been discussed so far. It adjusts utility revenues for any deviation between expected and actual sales regardless of the reason for the deviation. A variation of the full sales adjustment clause is the per-customer method, which sets a per-customer revenue target. In the years following a rate case, allowed revenues are adjusted for increases or decreases in the number of customers. In addition to Sales-Revenue Decoupling, another variation called “Sales-Margin Decoupling” separates margin recovery from sales by setting a margin-per-customer target. Any of these can use a forecast of revenue or use historical years to create a test year from which to derive the revenue target.
- 2. Net Lost Revenue Recovery, Lost Revenue Adjustments, or Conservation and Load Management Adjustment Clauses.** This mechanism adjusts net changes in revenues only for sales deviations that can be proven or demonstrated to have resulted from conservation and load-management programs. Revenues continue to be susceptible to variations in sales from all other causes. While favored by some observers, this mechanism has also been criticized as being less effective than decoupling because it does not remove the sales incentive, can require much more sophisticated monitoring and evaluation, and could allow utilities to recover costs for expenditures on programs that do not result in increased efficiency.
- 3. Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility’s revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers’ bills. This approach has been criticized for having the unintended effect of reducing customers’ incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.

5. Is decoupling new? What States have implemented a decoupling mechanism? Although only a few States have adopted it, decoupling itself is not a new idea; in fact, it has been implemented in some parts of the country for decades. California has the most experience with decoupling, having operated such a mechanism in the electricity sector from 1981 through 1996, and just recently restarting the system in the State. Others that have implemented decoupling are detailed on the map below.



Note that some of these States have recently adopted decoupling (like Idaho), others have been using it for some time (e.g. Maryland), some have considered and rejected it (e.g. Connecticut and Arizona), some have discontinued using it (e.g. Maine) and others have discontinued, and then returned to using decoupling (e.g. California).

6. Will decoupling raise customer bills? Because of the adjustment mechanism, some designs of decoupling could potentially result in **more frequent up-and-down changes in rates** for consumers. However, by increasing the frequency with which rates are brought into alignment with the PUC-approved revenue requirement, the changes should be smaller, and the likelihood of a sharp hike or decline in rates (common in traditional rate cases) may be reduced.

Decoupling could create higher bills for customers who do not participate in efficiency programs, although proponents of decoupling argue that these reductions would be diluted across a wide enough customer base to render any increases nearly unnoticeable. This may not occur, however, if decoupling is applied to a small customer class, where the effect of conservation in rates may be more pronounced.

Of special concern is the impact on low-income users, who would be least able to respond to changes in bills. Decoupling proponents note that this heightens the profile of targeted energy efficiency programs that serve these customers, lowering their bills without impacting utility revenues.

Others with concerns about decoupling comment that **unless it is designed to avoid doing so, decoupling could create unfair transfers between customer classes**. For example, if transfers between classes are allowed, commercial and industrial customers who are ineligible to participate in residential efficiency programs might see higher rates resulting from those programs.

Will rates go up for customers who implement energy efficiency? **Because they are consuming less, these customers' bills will go down.** Rates for all customers under a decoupling mechanism may increase in the short run when efficiency reduces sales because the utilities have to cover their costs and necessary returns on investments. In the example above, if the utility is selling fewer kWh of electricity, but its revenue requirement remains the same, each kWh will need to cover a greater share of the cost of service and will need to be priced higher. However, **any rate increases would be small, particularly when compared to the benefits for customers engaging in conservation,** and some analysis suggests the systemwide benefits from increased efficiency may outweigh costs for all customers⁸. Moreover, if efficiency programs cut sales without lessening fixed costs, under traditional regulation rate calculations would reflect that in the next rate case anyway.

Will decoupling result in rampant rate instability? In the experience of some States, such as New York, California, and Oregon, fluctuations in rates under decoupling were less than 1% for ratepayers in most years, and never exceeded 4%. **Customers may already see significantly greater rate variability through surcharges for fuel and purchased power.** Moreover, rate variability under decoupling may depend on a number of factors, including the program design, but also including other factors, like economic and weather variability. These examples and issues are discussed more in the section on "Does Decoupling Transfer Risk to Customers" section, later in the FAQ.

In theory, decoupling adjusts rates to more closely maintain the underlying relationship between prices and revenue requirements over time. **This should lessen the likelihood of large-scale "rate shocks" in the next rate case** (though this may vary based on the frequency of the reconciliation.) There are other mechanisms that can be put into place to reduce the frequency of large rate adjustments, including using a balancing account, applying a "Rate-Adjustment Band," or including a course-correction mechanism. These are also discussed in more detail in the "Off-Ramps & Adjustments" section later in the FAQ.

How is decoupling different from having more frequent rate cases? Decoupling does not change the rate base and rate of return decided in a rate case. It is also worth remembering that **decoupling affects revenue only between rate cases:** at the next rate case, the base rates are reset, using the mechanisms familiar to regulators in traditional cost of service regulation. Some have argued that a utility would not need decoupling if it regularly entered into rate cases. Decoupling proponents have replied that it is a mechanism used to make utilities indifferent to sales as a function of profits, and that regular rate cases remain essential but are not the same thing. Moreover, **rate cases are expensive and time consuming, and most consider it impractical to revise base rates with the frequency proposed for adjustments under decoupling.** In the 1990s, Wisconsin revised its base rates each year but discarded this approach because of the effort involved and the less-predictable incentive structure created for utilities by the short period between rate cases.⁹

7. Does decoupling transfer risk from the utilities to customers? Efficiency is not the only variable that can affect sales. For example, an unexpectedly hot summer can increase sales, or an economic downturn can drive commercial customers out of business and reduce sales. Under traditional regulation,

⁸ Rates may go up to restore the lost distribution revenue, but utility bills could also drop as cost-effective efficiency offsets the need to purchase more expensive kilowatt-hours or therms. In this case, the utility would be able to sell less electricity or gas with no corresponding loss of revenue, while customers would benefit by avoiding the costs of the electricity or gas that is not needed.

⁹ Some commenters have raised an objection to decoupling, making the case that **it violates a regulatory principle against single-issue ratemaking.** They note that decoupling focuses on efficiency and ignores other sources of costs increases & decreases that are considered in a traditional rate case that may counterbalance changes in rates from efficiency. Decoupling proponents argue that with normalization mechanisms, these other factors are taken into account and that decoupling simply raises the profile of demand-side management's effect on revenue. On a regulatory theory level, they assert that decoupling meets the requirements for a "tracker", a ratemaking instrument designed to take into account specific issues that have effects on rates.

risk is borne by utilities (and shared with customers via rate pass-throughs) for a number of factors that can affect sales that are beyond the utility's control. In both cases, the utility's fixed costs would remain the same, and changes in revenues would not be related to changes in underlying costs for the utility to provide service. Some argue that because decoupling constrains the utility's revenues to "normal weather" levels and economic trends, theoretically the utility's business and weather risk conveyed in rates for fixed costs is eliminated entirely. They have raised a concern that this represents a shift of risk from the utility to customers.

One of the main reasons some Public Utility Commissions are reluctant to explore decoupling is **the concern that revenues could remain stable for utilities even if weather or business factors cause customer rates to increase** or to incur large balances in deferral accounts, illustrated by Maine's experience in the 1990's (see box, this page.)

Maine's decoupling experience

If the impact of energy efficiency is not adequately anticipated during the rate case, sales will be lower than expected and rates will go up. But rates could also go up if sales are lower because of a mild summer or an economic downturn. This created a crisis in Maine, which had pioneered a decoupled rate design with Central Maine Power in 1991 but faced a recession in the early 1990s. The recession resulted in lower electricity sales, and the decoupling adjustments kicked in to reflect pre-recession target revenues, causing rates to go up when customers were least prepared to pay them. This sudden and sharp downturn in the Maine economy reduced consumption to a much greater degree than the utility's efficiency efforts, and decoupling became increasingly viewed as a mechanism that was shifting the economic impact of the recession from the utility to consumers, rather than providing the intended energy efficiency and conservation incentive impact. By 1993, deferrals accumulated by the adjustment mechanism had reached \$52 million, and the PUC and the utility agreed to end the experiment. (Maine PUC, 2004)

It should be noted that while decoupling is often cited as the culprit here, in fact the economic downturn was the problem. Traditional regulation would have eventually yielded rate changes through a traditional rate case and the resulting price increases would have reflected the same economic circumstances.

Proponents assert that decoupling can use normalization mechanisms to eliminate these risks or assign them appropriately, and some State experiences suggest that decoupling may not shift any risk to consumers. California's Electric Rate Adjustment Mechanism (or ERAM, which operated between 1981 and 1996) adjusted the target revenue based on factors affecting the cost of service which were beyond the utility's control, such as inflation or weather. A 1994 analysis of California's program found that "the record in California indicates that the risk-shifting accounted for by ERAM is small or non-existent and, in any case, ERAM has **contributed far less to rate volatility than have other adjustments to rates, such as the fuel-adjustment clause.**" The analysis concluded that California's decoupling created lower risks for consumers (that they could be faced with unexpected bill increases) and

profit risk reductions to utilities (who could be assured of fixed cost recovery, even in the face of efficiency improvements) (Eto et al, 1994).

The authors went further, undertaking a statistical analysis to calculate the dollar value of risk from shifts in weather and economic activity under decoupling in a hypothetical case. Based on these estimates, the authors concluded that with the normalization procedures used in this decoupling structure, the quantitative risk burden transferred to consumers would be one-fifth of one percent of electricity revenues from each of those customers – **a \$2 risk-shifting burden on a \$1200 annual bill.** (Eto et al, 1994)

Consolidated Edison in New York had a similar mechanism in place from 1993 to 1997. The rate variability under this system suggests that rate impacts were minimal here as well. In 1993, a shortfall with just under 3% effect on rates was collected from customers, and rates went up. For the next four years, over-collections occurred, and rates went down just under 1% per year. (NRDC, 2001)

Under some decoupling mechanisms (such as some of those implemented in the Pacific Northwest) **the revenue target can be adjusted to accommodate unexpected weather patterns.** Northwest Natural Gas in Oregon, for example, subtracts an estimated sales impact for weather from its periodic adjustment. A more complex, but comprehensive, approach is called “statistical recoupling,” in which weather, fuel costs, economic changes, and the number of customers is modeled, and that model is used to determine the revenue target. (Eric Hirst, 1993)

Some have raised a concern about statistical recoupling and other economic and weather normalization methods, commenting that **adding these systems makes decoupling so complicated that its administrative and accounting burdens can outweigh its benefits, or that it can be manipulated to allow “over-earning” by utilities.** Some proponents of decoupling respond that weather and economic risk is already shared with consumers through rates, and that the traditional rate case structure simply delays accounting for these costs (or revenues) until the next rate case. Moreover, weather normalization computations of some type are universally included in the determination of the revenue requirement in each rate case, with about half of the States allowing normalization adjustments between rate cases.

8. Will decoupling discourage utility companies from cutting their costs? No. Concerns have been raised that to the extent that utilities become isolated from possible changes in revenues, they have little motivation to lower their costs in order to meet their revenue requirement. However, **because decoupling affects only revenues, the utility remains at risk for any changes in costs.** Decoupling proponents argue that the rate case mechanism underlying decoupling continues to ensure that utilities strive to control fixed costs that cannot easily be reduced to the greatest degree possible. They note that performance indicators can also be included to identify when cost reductions have arisen from a decreased level of service rather than from gains in efficiency.

One solution pioneered by New Jersey in its Conservation Incentive Program allows gas utilities to adjust their rates to account for changes in consumption resulting from efficiency efforts, but **the adjustment is capped at the amount of verifiable supply cost reductions achieved by the utility.** (Fox et al, 2007)

9. Can a utility increase its profitability with decoupling? Yes. With a per-customer form of decoupling, utilities receive their revenue from customers that cover the fixed costs of service, and that cost of service includes a rate of return that contributes to profits. In other words, instead of making more money by selling more kilowatt hours or therms, utilities would make more money when they increase their customer base, regardless of whether there is a corresponding increase in sales. Alternatively, **if the utility can find a way to improve its efficiency and thereby lower its cost of service without decreasing its number of customers, it has an opportunity to improve its bottom line.** Under decoupling, the primary driver for profitability growth is the addition of new customers, especially in areas where the addition of new customers does not carry high infrastructure addition costs. In these cases, the customers who would bring the greatest potential profitability to a utility are those who are the most energy efficient, since they can be added with the lowest incremental addition to the utility’s cost of service¹⁰.

As noted before, decoupling can reduce risk for the utility by ensuring that its revenues and return on investment remain stable. **A lower risk-profile should make the cost of capital lower for the utility¹¹.** For investors, this can be realized through an increase in the utility’s debt/equity ratio, a decrease in the return on equity, improved debt ratings and credit requirements.

¹⁰ Again, this may reflect differences between regions and sectors: where unexpectedly adding new customers brings significant new operating costs not anticipated in the rate case, the outcome may be different and, as would occur in traditional ratemaking, could trigger a rate case.

¹¹ Illustrating this, one utility has proposed a lower target return as part of its decoupling proposals in MD and DC.

10. Is decoupling different for gas than it is for electricity? Decoupling is fundamentally the same for both gas and electric utilities. They both share similar cost structures which are dominated by high fixed costs. However, the two industries are facing different underlying trends in customer revenues. While the gas industry generally faces declining average revenues per customer over time, the electric industry is experiencing increasing average revenues per customer. As a result, gas utilities tend to face revenue and profit erosion between rate cases, while electric utilities garner increasing revenue and profits between rate cases. Decoupling has the effect of eliminating most of these effects. As a result, gas utilities have tended to be more open to implementing decoupling than have electric utilities. However, a small but growing number of electric utilities have either implemented, requested or are investigating decoupling. Some have suggested that this could be partly in response to longer-term expectation about capital expenditures and environmental costs. Energy efficiency may be a cost-effective way to avoid potential future risks such as carbon regulation. In addition, recent policy initiatives at both the federal and State level have embraced energy efficiency as a high priority resource¹². If energy efficiency is deployed more widely in the future, electric utilities may become more interested in decoupling.

What off-ramps and adjustments are possible?

Decoupling is a substantial departure from traditional rate-making, and may be new to States and utilities. Therefore it makes sense to approach implementation with caution, considering corrective mechanisms to ensure that the change in structure has the intended effects and avoids harmful unintended consequences. Some of the mechanisms that have been considered are:

Balancing Accounts: Depending on the frequency of adjustments, a separate account can be established and used to track and accumulate over- or under-collections, in order to defer the adjustment and “smooth out” unusual spikes in rates. Typically this kind of account is used when adjustments are scheduled to occur less frequently.

Rate banding: As discussed above, this triggers the periodic adjustment to rates when the changes in revenue would result in a change within a certain percentage. If the rate band were set to 10% over or under the target rate, only changes less than 10% would trigger the adjustment. Outside the band, a new rate case would be triggered.

Revenue banding / shared earnings: In order to prevent unintended windfalls or shortfalls by the utility, earnings greater or less than certain limits can be shared with customers. For example, if an earnings band is set to 5% of return on equity compared to the allowed return found in the most recent rate case, earnings or shortfalls greater than 5% would be shared with consumers on a proportional basis through rates. This can also be computed on the basis of revenue changes, which avoids the complication (and potential litigation) of computing returns on equity.

Course corrections for single events, changes in industrial customers or activity: The addition of a new customer among large users, such as an industrial customer, or large change in the activity of a customer—a factory adding a new shift, for example—can have a disproportionate effect on rates for other customers in that class. In these cases, language allowing for adjustments that take special circumstances into account can help avoid unexpected rate shifts.

11. Would decoupling work the same for regulated and deregulated States? Broadly speaking, utilities in deregulated markets appear to be more vulnerable to revenue losses incurred by decreased sales from efficiency than utilities in vertically-integrated markets. In the 2006 report on the National Action Plan For Energy Efficiency, the authors note that “once divested of a generation plant, the

¹² For more on energy efficiency as a high priority resource, see the National Council on Electricity Policy’s study for DOE’s Section 139 Report To Congress (2006) and the National Action Plan on Energy Efficiency, (2006).

distribution utility is a smaller company (in terms of total rate base and capitalization), and fluctuations in throughput and earnings have a relatively larger impact on return.” (NAPEE, 2006)

In States where distribution utilities purchase most or all of their commodities from a wholesale market, decoupling would be integrated into the largely-fixed cost structure of the distribution utilities. In States with vertically integrated utilities, decoupling can also be applied, but care must be taken in the rate case context to accurately separate fixed costs from variable costs, applying the decoupling adjustments only to the fixed costs. In all other respects, decoupling is applied in the same manner in both types of situations.

12. Where can I find out more? This FAQ was authored by Miles Keogh of NARUC’s Grants & Research staff with funding from the U.S. Environmental Protection Agency. It was developed through research, interviews, and input from a number of parties, including the staffs of the New Jersey Board of Public Utilities, Massachusetts Department of Public Utilities, Arizona Corporation Commission, US Environmental Protection Agency, North Carolina Attorney General’s Office, and Public Service Commission of the District of Columbia. Oversight was provided by Commissioner Rick Morgan of the District of Columbia PSC, and technical assistance came from Wayne Shirley of the Regulatory Assistance Project. More resources on decoupling are included below.

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BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON

Chairman

WILLIAM A. MUNDELL

Commissioner

JEFF HATCH-MILLER

Commissioner

KRISTIN K. MAYES

Commissioner

GARY PIERCE

Commissioner

IN THE MATTER OF THE APPLICATION OF)
SOUTHWEST GAS CORPORATION FOR THE)
ESTABLISHMENT OF JUST AND)
REASONABLE RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF SOUTHWEST GAS)
CORPORATION DEVOTED TO ITS)
OPERATIONS THROUGHOUT ARIZONA.)

DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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I. INTRODUCTION

Q. Please State your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in approximately 400 utility proceedings before 40 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") proceedings, including the recent electric rate cases involving Arizona Public Service Company (Docket No. E-01345A-05-0816), UNS Gas, Inc. (Docket No. G-01345A-05-0463), UNS Electric, Inc. (Docket No. E-0404A-06-0783) and Tucson Electric Power Co. (Docket No. E-01933A-07-0402). Those testimonies were provided on behalf of the Utilities Division Staff.

1 **Q. Do any of your previous testimonies involve rate proceedings of Southwest Gas?**

2 A. Yes. I have previously testified in several rate proceedings involving Southwest Gas
3 Corporation ("Southwest Gas" or "Company"). These cases were before both this
4 Commission and the Nevada Public Service Commission.
5

6 **Q. What is the purpose of your testimony in this proceeding?**

7 A. I have been retained by the Utilities Division Staff to evaluate the cost of capital aspects of
8 the most recent filing of Southwest Gas. I have performed independent studies and am
9 making recommendations on the current cost of capital for Southwest Gas. My testimony
10 also responds to the Company's cost of capital proposals sponsored by Southwest Gas
11 witness Frank J. Hanley.
12

13 **Q. Have you prepared an exhibit in support of your testimony?**

14 A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 12. This
15 exhibit was prepared either by me or under my direction. The information contained in
16 this exhibit is correct to the best of my knowledge and belief.
17

18 **II. RECOMMENDATIONS AND SUMMARY**

19 **Q. What are your recommendations in this proceeding?**

20 A. My overall cost of capital recommendations for Southwest Gas are:
21

	Percent	Cost	Return
Short-Term Debt	0.00%	N/A	N/A
Long-Term Debt	52.08%	7.96%	4.15%
Preferred Stock	4.48%	8.20%	0.37%
Common Equity	43.44%	9.3-10.5%	4.13-4.56%
Total	100.00%		8.55-9.07%
		8.86% with 10.0% ROE	

Southwest Gas' application requests a return on common equity of 11.25 percent and a total cost of capital of 9.45 percent. This cost of capital is based on a hypothetical capital structure comprised of 51 percent long-term debt, 4 percent preferred stock, and 45 percent common equity.

Q. Please summarize your cost of capital analyses and related conclusions for Southwest Gas.

A. This proceeding is concerned with Southwest Gas' regulated natural gas utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. Southwest Gas' proposed capital structure is the "target" capital structure ratios of the Company, which is actually a hypothetical capital structure. I do not use this hypothetical capital structure in my cost of capital analyses, but rather use the Company's actual test period capital structure ratios.

The second step in a cost of capital calculation is a determination of the embedded cost rates of long-term debt and preferred stock. I have used the 7.96 percent cost rate for long-term debt and the 8.20 percent cost rate for preferred stock, both of which are contained in Southwest Gas' application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for Southwest Gas. Each of these methodologies is applied to two groups of proxy utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.3-10.4%
Capital Asset Pricing Model	9.5-9.8%
Comparable Earnings	10.0-10.5%

1 Based upon these findings, I conclude that the cost of common equity for the proxy
2 utilities is within a range of 9.3 percent to 10.5 percent (9.9 percent mid-point). This
3 range is determined by the results of all three of my cost of equity methodology results,
4 since all three sets of results fall within this range. I recommend that Southwest Gas' cost
5 of equity be slightly above the mid-point of my 9.3 percent to 10.5 percent range or 10.0
6 percent. I recommend a slightly higher cost of equity in order to recognize the impact of
7 Southwest Gas' lower equity ratio and debt ratings, relative to those of the proxy groups.
8

9 Combining the capital structure and individual cost rates, results in a weighted cost of
10 capital for Southwest Gas. My recommendation overall cost of capital range is 8.55
11 percent to 9.07 percent (8.86 percent with 10.0 percent cost of equity). I recommend an
12 8.86 percent cost of capital for Southwest Gas.
13

14 **III. ECONOMIC PRINCIPLES AND METHODOLOGIES**

15 **Q. What are the primary economic principles that establish the standards for**
16 **determining a fair rate of return for a regulated utility?**

17 **A.** Public utility rates are normally established in a manner designed to allow the recovery of
18 their costs, including capital costs. This is frequently referred to as "cost of service"
19 ratemaking. Rates for regulated public utilities traditionally have been primarily
20 established using the "rate base - rate of return" concept. Under this method, utilities are
21 allowed to recover a level of operating expenses, taxes, and depreciation deemed
22 reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of
23 return on the assets utilized (i.e., rate base) in providing service to their customers.
24

25 The rate base is derived from the asset side of the utility's balance sheet as a dollar amount
26 and the rate of return is developed from the liabilities/owners' equity side of the balance

1 sheet as a percentage. Thus, revenue impact of the cost of capital is derived by
2 multiplying the rate base by the rate of return, including income taxes.

3 The rate of return is developed from the cost of capital, which is estimated by weighting
4 the capital structure components (i.e., debt, preferred stock, and common equity) by their
5 percentages in the capital structure and multiplying these values by their cost rates. This
6 is also known as the weighted cost of capital.

7
8 Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post
9 (after the fact) earned return on an asset base, while the cost of capital is an economic and
10 financial concept which refers to an ex ante (before the fact) expected or required return
11 on a liability base. In regulatory proceedings, however, the two terms are often used
12 interchangeably. I have equated the two concepts in my testimony.

13
14 From an economic standpoint, a fair rate of return is normally interpreted to mean that an
15 efficient and economically managed utility will be able to maintain its financial integrity,
16 attract capital, and establish comparable returns for similar risk investments. These
17 concepts are derived from economic and financial theory and are generally implemented
18 using financial models and economic concepts.

19
20 From a legal perspective, while I am not a lawyer, it is my understanding that two United
21 States Supreme Court decisions provide the controlling standards for a fair rate of return.
22 The first decision is Bluefield Water Works and Improvement Co. v. Public Serv.
23 Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

24
25 *What annual rate will constitute **just compensation** depends upon many*
26 *circumstances and must be **determined by the exercise of fair and***
27 ***enlightened judgment**, having regard to all relevant facts. A **public utility***
28 *is entitled to such rates as will permit it to **earn a return** on the value of the*
29 *property which it employs for the convenience of the public equal to that*
30 ***generally being made** at the same time and in the same general part of the*

1 country on *investments in other business undertakings* which are *attended*
2 *by corresponding risks and uncertainties*; but it has no *constitutional*
3 *right to profits* such as are realized or anticipated in *highly profitable*
4 *enterprises or speculative ventures*. The *return* should be reasonably
5 sufficient to assure confidence in the *financial soundness* of the utility, and
6 should be adequate, *under efficient and economical management*, to
7 maintain and *support its credit* and *enable it to raise the money* necessary
8 for the proper discharge of its public duties. A rate of return may be
9 reasonable at one time, and become too high or too low by changes
10 affecting opportunities for investment, the money market, and business
11 conditions generally. [Emphasis added.]

12
13 Thus, the Bluefield decision, in my opinion as a non-lawyer, established the following
14 standards for a fair rate of return: comparable earnings, financial integrity, and capital
15 attraction. It also noted the changing level of required returns over time as well as an
16 underlying assumption that the utility be operated in an efficient manner.

17
18 The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591
19 (1942). In that decision, the Court stated:

20
21 *The rate-making process under the [Natural Gas] Act, i.e., the fixing of*
22 *'just and reasonable' rates, involves a balancing of the investor and*
23 *consumer interests From the investor or company point of view it is*
24 *important that there be enough revenue not only for operating expenses but*
25 *also for the capital costs of the business. These include service on the debt*
26 *and dividends on the stock. By that standard the return to the equity owner*
27 *should be commensurate with returns on investments in other enterprises*
28 *having corresponding risks. That return, moreover, should be sufficient to*
29 *assure confidence in the financial integrity of the enterprise, so as to*
30 *maintain its credit and to attract capital.* [Emphasis added.]
31

32 The three economic and financial parameters in the Bluefield and Hope decisions -
33 comparable earnings, financial integrity, and capital attraction - reflect the economic
34 criteria encompassed in the "opportunity cost" principle of economics. The opportunity
35 cost principle provides that a utility and its investors should be afforded an opportunity
36 (not a guarantee) to earn a return commensurate with returns they could expect to achieve
37 on investments of similar risk. The opportunity cost principle is consistent with the

1 fundamental premise, on which regulation rests, namely, that it is intended to act as a
2 surrogate for competition.

3
4 I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set
5 forth the legal requirements applicable to determining fair rate of return in Arizona. In
6 Simms v. Round Valley Light & Power Company,¹ the Arizona Supreme Court took
7 exception to application of the following principle in Arizona since the Constitution
8 mandates consideration of fair value:

9
10 *"In the Hope case the court, in testing the reasonableness of rates fixed by*
11 *the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A.*
12 *Section 717 et seq., after holding that congress had provided no formula by*
13 *which just and reasonable rates were to be determined, ruled that it was*
14 *the final result reached and not the method used in reaching the result that*
15 *was controlling and that it was unimportant to 'determine the various*
16 *permissible ways in which any rate base on which the return is computed*
17 *might be arrived at.'*

18
19 My testimony does not advocate that the Commission ignore the *Simms* holding in this
20 regard, or the fair value of Southwest Gas' property, which it is required to consider under
21 Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield
22 decisions to be helpful in their discussion of comparable earnings, financial integrity and
23 capital attraction. I note that Southwest Gas Electric Witness Hanley also cites the Hope
24 and Bluefield cases as "guidelines" for evaluating the cost of capital for the Company.

25
26 **Q. How can these parameters be employed to estimate the cost of capital for a utility?**

27 **A.** Neither the courts nor economic/financial theory have developed exact and mechanical
28 procedures for precisely determining the cost of capital. This is the case because the cost
29 of capital is an opportunity cost and is prospective-looking, which dictates that it must be
30 estimated.

¹ 294 P.2d 378 (1956).

1 There are several useful models that can be employed to assist in estimating the cost of
2 equity capital, which is the capital structure item that is the most difficult to determine.
3 These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"),
4 comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods
5 (or models) differs from the others and each, if properly employed, can be a useful tool in
6 estimating the cost of common equity for a regulated utility. Many state regulatory
7 commissions rely upon the DCF and CAPM models to develop the cost of common
8 equity for utilities.

9
10 **Q. Which methods have you employed in your analyses of the cost of common equity in**
11 **this proceeding?**

12 A. I have utilized three methodologies to determine Southwest Gas' cost of common equity:
13 the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses
14 although, as discussed later, my CAPM analysis is a form of the RP methodology. Each
15 of these methodologies will be described in more detail in my testimony that follows.

16
17 **IV. GENERAL ECONOMIC CONDITIONS**

18 **Q. Why are economic and financial conditions important in determining the costs of**
19 **capital?**

20 A. The costs of capital, for both fixed-cost (debt and preferred stock) components and
21 common equity, are determined in part by current and prospective economic and financial
22 conditions. At any given time, each of the following factors has an influence on the costs
23 of capital: the level of economic activity (i.e., growth rate of the economy), the stage of
24 the business cycle (i.e., recession, expansion, or transition), and the level of inflation. The
25 Supreme Court, in its Bluefield decision, which noted that "[a] rate of return may be
26 reasonable at one time, and become too high or too low by changes affecting opportunities
27 for investment, the money market, and business conditions generally."

1 **Q. What indicators of economic and financial activity have you evaluated in your**
2 **analyses?**

3 A. I have examined several sets of economic statistics from 1975 to the present. I chose this
4 time period because it permits the evaluation of economic conditions over three full
5 business cycles plus the current cycle to date, allowing for an assessment of changes in
6 long-term trends. This period also approximates the beginning and continuation of active
7 rate case activities by public utilities.

8
9 A business cycle is commonly defined as a complete period of expansion (recovery and
10 growth) and contraction (recession). A full business cycle is a useful and convenient
11 period over which to measure levels and trends in long-term capital costs because it
12 incorporates the cyclical (i.e., stage of business cycle) influences, and thus, permits a
13 comparison of structural (or long-term) trends.

14
15 **Q. Please describe the timeframe of the three prior business cycles and the most current**
16 **cycle.**

17 A. The three prior complete cycles and current cycle cover the following periods:

<u>Business Cycle</u>	<u>Expansion Cycle</u>	<u>Contraction Period</u>
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present	

22
23 **Q. Do you have any general observations concerning the changing trends in economic**
24 **conditions and their impact on costs over this broad period?**

25 A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity and
26 stability over the period since the early 1980s. This period has been characterized by
27 longer economic expansions, relatively tame contractions, relatively low and declining

1 inflation, and declining interest rates and other capital costs. The current business cycle
2 began in late 2001, following a somewhat modest recession earlier in the year. Over the
3 past several months, the economy has slowed, largely as a result of the collapse of the
4 "sub-prime" mortgage market. There is some concern that the economy may slide into a
5 recession, but this is unclear at this time. Should the economy incur a recession, the
6 impacts on cost of capital would likely be characterized by lower utility growth and
7 declining capital costs.

8
9 **Q. Please describe recent and current economic and financial conditions and their**
10 **impact on the costs of capital.**

11 A. Schedule 2 shows several sets of economic data. Pages 1 and 2 contain general
12 macroeconomic statistics while Pages 4 through 6 contain financial market statistics.
13 Pages 1 and 2 of Schedule 2 show that the U.S. economy is currently beginning the
14 seventh year of an economic expansion although, as indicated previously, the economy is
15 currently slowing. This is indicated by the growth in real (i.e., adjusted for inflation)
16 Gross Domestic Product, industrial production, and the unemployment rate. This current
17 expansion has generally been characterized as slower growth, in comparison to prior
18 expansions. This has resulted in lower inflationary pressures and interest rates. In
19 addition, the current slowing of the economy has resulted in a lowering of interest rates.

20
21 The rate of inflation is also shown on Pages 1 and 2 of Schedule 2. As is reflected in the
22 Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-
23 1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation
24 declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991
25 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 4.1 percent rate of
26 inflation in 2007 was slightly above the levels since 2000, but is well below the levels of
27 the past thirty years.

1 **Q. What have been the trends in interest rates?**

2 A. Pages 3 and 4 of Schedule 2 show the levels and trends in interest rates. Rates rose
3 sharply to record levels in 1975-1981 when the inflation rate was high and generally
4 rising. Interest rates declined substantially in conjunction with inflation rates throughout
5 the remainder of the 1980s throughout the 1990s. Interest rates declined even further from
6 2000-2005 and generally recorded their lowest levels since the 1960s.

7
8 During the past several years, long-term interest rates have remained low by historic
9 standards. During the 2001 recession and early in the succeeding expansion, the Federal
10 Reserve lowered interest rates (i.e., Federal Funds rate) 11 times in 2001 and twice in
11 2003 in an effort to stimulate the economy. Following this the Federal Reserve increased
12 short-term interest rates on 17 occasions between 2004 and 2006, although each time by
13 only 0.25 percent, in an attempt to ensure that any perceived inflationary expectations will
14 not stifle continued economic growth. Nevertheless, the economic recovery to date has
15 not resulted in a pronounced increase in long-term rates. Most recently, however, the
16 Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) on five
17 occasions.

18
19 **Q. What have been the trends in common share prices?**

20 A. Pages 5 and 6 of Schedule 2 show the levels and trends in common stock prices and ratios.
21 These indicate that share prices were essentially stagnant during the high inflation/interest
22 rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991
23 business cycle and the most recent cycle have witnessed a significant upward trend in
24 stock prices. During the initial years of the current expansion, however, stock prices were
25 volatile and declined substantially from their highs reached in 1999 and early 2000. Share
26 prices have increased somewhat since 2003 but have been volatile.

27

1 **Q. What conclusions do you draw from this discussion of economic and financial**
2 **conditions?**

3 A. It is apparent that capital costs are currently low in comparison to the levels that have
4 prevailed over the past three decades. In addition, the current weakness in the economy
5 has resulted in a decline in capital costs. Therefore, it can reasonably be expected that
6 cost of equity models currently produce returns that are lower than returns experienced in
7 prior years.
8

9 **V. SOUTHWEST GAS' OPERATIONS AND RISKS**

10 **Q. Please summarize Southwest Gas and its operations.**

11 A. Southwest Gas is an operating gas distribution company. The Company is engaged in the
12 business of purchasing, transporting and distributing natural gas to residential,
13 commercial, and industrial customers in geographically diverse portions of Arizona,
14 Nevada and California. Southwest Gas also owns Paiute Pipeline Co., as well as Northern
15 Pipeline Construction Company. Until 1996, Southwest Gas owned PriMerit Bank
16 (formerly Nevada Savings and Loan).
17

18 **Q. What are the current security ratings of Southwest Gas?**

19 A. As is shown on Schedule 3, the current bond ratings of Southwest Gas are:

21	Moody's	Baa3
22	Standard & Poor's	BBB-
23	Fitch	BBB

24
25 As this indicates, Southwest Gas' bonds presently carry triple B ratings by the three rating
26 agencies who rate the Company's debt.
27

1 **Q. What has been the trend in Southwest Gas' debt ratings?**

2 A. This is also depicted on Schedule 3. As this Schedule indicates, the Company's debt
3 ratings have been triple B since at least 1995.

4
5 **Q. How have the rating agencies recently described Southwest Gas?**

6 A. An example of this is provided in an October 11, 2007 RatingsDirect report on Southwest
7 Gas by Standard & Poor's. In this report, Standard & Poor's stated:

8
9 *The ratings on Southwest Gas Corp. are based on its strong*
10 *business position rating of '4' (Standard & Poor's Rating Services*
11 *rates a company's business position on a scale of '1' (excellent to*
12 *'10' (vulnerable)) as a regulated local gas distribution company*
13 *serving the high-growth service territories in Arizona, Nevada, and,*
14 *to a lesser extent, California. The ratings also reflect improving*
15 *operating efficiency and an intermediate financial risk profile.*
16 *These factors are partially offset by low customer usage due to its*
17 *warm weather, geographic location, challenges associated with*
18 *improving regulatory treatment in certain jurisdictions, and a*
19 *moderately sized unregulated utility construction and maintenance*
20 *business.*

21
22 *The company provides natural gas to more than 1.8 million*
23 *customers in Arizona (54% of customers), Nevada (36%), and*
24 *California (10%). Residential and small commercial customers*
25 *account for nearly all of retail consumption and around 86% of the*
26 *company's total operating margin. Retail sales are sensitive to*
27 *weather, which has been a particular challenge for Southwest Gas,*
28 *given the gradual warming trend observed in its region. . . .*

29
30 *Strong customer growth, averaging 5% annually from 2001 to*
31 *2006, has helped to offset the effects of declining per capita*
32 *consumption, allowing for about a 3% annual increase in*
33 *residential throughput total volumes during the period. Nevada*
34 *and Arizona have been the two fastest-growing states in the U.S.*
35 *Customer growth has also driven capital requirements, which*
36 *increased by about 5.4% annually for the same period. The*
37 *company projects capital spending will total about \$880 million*
38 *over the 2007-2009 period, with about \$337 million (\$306 million*
39 *in 2006) to be spent in 2007. Customer growth is expected to*
40 *moderate in 2007 to about 3%, partially based on the recent*
41 *weakness in the housing markets of Phoenix and Las Vegas. This*
42 *may ease capital spending requirements a bit in the near term.*

1 *Southwest Gas depends on regulatory approval of retail rates to*
2 *cover the cost requirements associated with rapid growth, high*
3 *natural gas price volatility, and exposure to weather variation. All*
4 *three of the state regulatory commissions that oversee Southwest's*
5 *retail rates have allowed the company to recover its actual*
6 *purchased-gas costs through a purchased-gas adjustment*
7 *mechanism (PGA). In 2006, the Nevada commission approved the*
8 *company's gas cost adjustment on a quarterly basis.*

9
10 *Arizona regulation uses a historical test year, which creates a*
11 *regulatory lag, especially when considering the state's high growth*
12 *rate. Some of this is mitigated by the company's policy of receiving*
13 *advances from home builders to prefund construction expenditures*
14 *to new home developments, which are later refunded once the new*
15 *homeowners are hooked up and receiving gas. . . .*

16
17 *Financial performance measurably improved since mid-2006 as a*
18 *result of regulatory relief and customer growth. Capital outlays*
19 *remain high, although the company funded about 66% of capital*
20 *outlays with internal cash flow after dividends in fiscal 2006. The*
21 *company expects this ratio to improve to about 90% in 2008.*

22
23 *Credit measures are strong for the rating, with adjusted funds from*
24 *operations (FFO) to total debt of about 19% and adjusted FFO*
25 *interest coverage of about 3.6x for the 12-month period ended June*
26 *30, 2007. Meanwhile, debt leverage has decreased, with adjusted*
27 *debt to capital at 58% on June 20, 2007, down substantially from*
28 *69% in 2005.*

29
30 *The outlook on Southwest Gas is positive. The positive outlook*
31 *reflects our expectation of consistently strong cash flow measures*
32 *and declining debt leverage, primarily as a result of anticipated*
33 *high levels of internal funding of capital expenditures, minimal new*
34 *debt financing, and regulator annual equity infusions under the*
35 *company's common equity shelf and dividend reinvestment*
36 *programs. Significant rate design improvements could further yield*
37 *ratings improvement.*

38
39 **Q. Are you aware that Southwest Gas is requesting certain regulatory cost-recovery**
40 **mechanisms in this proceeding?**

41 **A.** Yes, I am. It is my understanding that the Company is requesting approval to implement
42 two new rate design proposals that, if approved, will be risk-reducing. These two
43 proposals involve a Weather Normalization Adjustment Provision ("WNAP") and a

1 Revenue Decoupling Adjustment Provision ("RDAP"). On a combined basis, these
2 provide for "Full Revenue Decoupling" for Southwest Gas' residential customers and all
3 but its largest general service customers.

4
5 **Q. How are these proposals risk-reducing to the Company?**

6 A. These rate design proposals, if approved, are risk-reducing to Southwest Gas since the
7 Company's revenues, and income, will be essentially insulated from variations due to
8 weather and usage. The net effect of these proposals is to transfer a significant portion of
9 the Company's risks from its shareholders to its ratepayers. Yet, it does not appear that
10 the Company acknowledges this risk transfer in terms of its requested rate of return.

11
12 **Q. Is the Staff recommending approval of these new proposals which would transfer**
13 **significantly more risk to ratepayers?**

14 A. Other Staff witnesses are addressing the Company's new risk-reducing rate design
15 proposals. It is my understanding that the Staff is opposed to them. However, I want to
16 point out that if the Commission should adopt either of them, I would recommend a
17 further downward adjustment to my recommended rate of return in consideration of the
18 reduced risk. The Company should have recognized a reduction to its rate of return in
19 recognition of its risk reducing proposals.

20
21 **VI. CAPITAL STRUCTURE AND COST OF DEBT**

22 **Q. What is the importance of determining a proper capital structure in a regulatory**
23 **framework?**

24 A. A utility's capital structure is important because the concept of rate base – rate of return
25 regulation requires that a utility's capital structure be determined and utilized in estimating
26 the total cost of capital. Within this framework, it is proper to ascertain whether the

1 utility's capital structure is appropriate relative to its level of business risk and relative to
2 other utilities.

3
4 As discussed in Section III of my testimony, the purpose of determining the proper capital
5 structure for a utility is to help ascertain its capital costs. The rate base – rate of return
6 concept recognizes the assets employed in providing utility services and provides for a
7 return on these assets by identifying the liabilities and common equity (and their cost
8 rates) used to finance the assets. In this process, the rate base is derived from the asset
9 side of the balance sheet and the cost of capital is derived from the liabilities/owners'
10 equity side of the balance sheet. The inherent assumption in this procedure is that the
11 dollar values of the capital structure and the rate base are approximately equal and the
12 former is utilized to finance the latter.

13
14 The common equity ratio (i.e., the percentage of common equity in the capital structure) is
15 the capital structure item which normally receives the most attention. This is the case
16 because common equity: (1) usually commands the highest cost rate; (2) generates
17 associated income tax liabilities; and, (3) causes the most controversy since its cost cannot
18 be precisely determined.

19
20 **Q. How have you evaluated the capital structure of Southwest Gas?**

21 A. I have first examined the five year historic (2003-2007) capital structure ratios of
22 Southwest Gas. Schedule 4 shows the historic capital structure ratios of the Company.
23 The respective common equity ratios are as follows:

	<u>Inc'l S-T Debt</u>	<u>Exc'l S-T Debt</u>
2003	33.0%	34.0%
2004	35.8%	35.8%
2005	34.4%	36.8%
2006	38.9%	39.4%
2007	41.0%	41.9%

This indicates a rising common equity ratio over this period. In fact, the most current common equity ratios significantly exceed the levels of five years ago.

Q. How do these capital structure ratios compare to the gas distribution utility industry?

A. I have prepared Schedule 5 to make this comparison. Page 1 of this schedule shows the 2002-2006 capital structure ratios of the Value Line group of LDC's, excluding short-term debt. Page 2 of Schedule 5 indicates the 2002-2006 capital structure ratios for this group, including short-term debt. The average ratios are:

	<u>Inc'l S-T Debt</u>	<u>Exc'l S-T Debt</u>
2002	41%	47.4%
2003	43%	50.4%
2004	43%	51.4%
2005	44%	51.9%
2006	48%	53.1%

These common equity ratios are slightly higher than those of the most recent Southwest Gas ratios.

Q. What capital structure ratios has Southwest Gas requested in this proceeding?

A. The Company requests use of the following "target" capital structure:

Capital Item	Percent
Long-Term Debt	51.0%
Preferred Stock	4.0%
Common Equity	45.0%

This capital structure contains slightly more common equity than the most recent actual capital structures for 2007 which contained a common equity ratio of 41.0 percent including short-term debt, and 41.9 percent exclusive of short-term debt.

Q. What is basis of the Company's capital structure request?

A. In the last rate proceeding of Southwest Gas (Docket No. G-01551A-04-0876), this Commission approved use of a hypothetical capital structure for the Company that contained 55 percent long-term debt, 5 percent preferred stock, and 40 percent common equity. This 40 percent common equity ratio exceeded the actual test period equity ratio (34.1 percent, according to Mr. Wood's testimony, page 5) and was apparently intended to be an "incentive" for the Company to raise its actual equity ratio. As stated by Mr. Wood, in its Decision in this proceeding, the Commission directed the Company to submit a "recapitalization plan" explaining how it intends to achieve an actual 40 percent common equity ratio.

In the present case, the Company is again requesting a hypothetical capital structure, with an even higher common equity ratio, at 45 percent. Southwest Gas witness Wood describes this as a "target" common equity ratio and he indicates (page 9) "it is reasonable to assume that the Company will achieve 45 percent common equity ratio...."

Q. Has the Company raised its equity ratio since the last case?

A. Yes, it has. The actual test period capital structure of the Company contains some 43.4 percent common equity.

1 **Q. Is it necessary to again utilize a hypothetical capital structure for Southwest Gas?**

2 A. No, it is not. The Commission provided the Company with a capital structure incentive in
3 the last case. The Company responded and achieved an equity ratio that satisfied the
4 Commission's directive. In this regard, it is noteworthy that Southwest Gas has
5 historically maintained a common equity ratio that was considerably below that of natural
6 gas distribution utilities in general. At the present time, the Company's capital structure is
7 more in line with that of other gas utilities.

8
9 **Q. What other reasons support the use of the Company's actual capital structure.**

10 A. I believe that, in general, utilities should use their actual capital structure for ratemaking
11 purposes unless there is a showing that the actual capital structures are significantly out of
12 line with other utilities. In the case of Southwest Gas, this is not a factor. Should the
13 Company want to have its rates set based upon 45 percent common equity ratio, it has the
14 option of raising new common equity in order to actually achieve this level of equity. In
15 any event, the circumstances have changed since the last case and no "incentive" is
16 required at this time.

17
18 **Q. What capital structure have you used in your analyses?**

19 A. I have utilized the actual test period capital structure of the Company in my analyses.
20 These are shown on my Schedule 1. I note that I normally include short-term debt in my
21 cost of capital calculations and I understand that this Commission also uses short-term
22 debt. However, in this case, it appears that Southwest Gas did not have any short-term
23 debt at the end of the test period, so I did not include any in the capital structure.

24

1 **Q. What cost rates of long-term debt and preferred stock have you used in your**
2 **analysis?**

3 A. I have utilized the 7.96 percent cost of long-term debt and 8.20 percent cost of preferred
4 stock shown in the Company's filing.

5
6 **Q. Can the cost of common equity be determined with the same degree of precision as**
7 **the costs of debt and preferred stock?**

8 A. No. The cost rates of debt and preferred stock are largely determined by interest
9 payments, issue prices, and related expenses. The cost of common equity, on the other
10 hand, cannot be precisely quantified, primarily because this cost is an opportunity cost.
11 As discussed earlier, there are, however, several models which can be employed to
12 estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and
13 CE - are developed in the following sections of my testimony.

14
15 **VII. SELECTION OF PROXY GROUPS**

16 **Q. How have you estimated the cost of common equity for Southwest Gas?**

17 A. Southwest Gas is a publicly-traded company. Consequently, it is possible to directly
18 apply cost of equity models to this entity. It is customary to analyze groups of comparison
19 or "proxy" companies as a substitute for Southwest Gas to determine its cost of common
20 equity.

21
22 I have examined two such groups for comparison to Southwest Gas. The first group of
23 proxy companies is the group of gas distribution companies followed by Value Line,
24 except for those companies that have not paid cash dividends. This group, which reflects
25 a representative sample of LDC's, is a proper proxy for Southwest Gas.
26

1 The second proxy group is the group of eight natural gas utilities Mr. Hanley utilized in
2 his testimony.

3
4 I note that, by developing my own group of proxy companies, used in conjunction with the
5 groups of proxy companies utilized by Southwest Gas witness Hanley, I have given
6 consideration to the Company's view as to the appropriate composition of the proxy
7 companies for Southwest Gas.

8
9 **VIII. DISCOUNTED CASH FLOW ANALYSIS**

10 **Q. What is the theory and methodological basis of the discounted cash flow model?**

11 A. The DCF model is one of the oldest, as well as the most commonly-used, models for
12 estimating the cost of common equity for public utilities. The DCF model is based on the
13 "dividend discount model" of financial theory, which maintains that the value (price) of
14 any security or commodity is the discounted present value of all future cash flows.

15
16 The most common variant of the DCF model assumes that dividends are expected to grow
17 at a constant rate. This variant of the dividend discount model is known as the constant
18 growth or Gordon DCF model. In this framework cost of capital is derived by the
19 following formula:

20
21
$$K = \frac{D}{P} + g$$

22

23 where: K = discount rate (cost of capital)

24 P = current price

25 D = current dividend rate

26 g = constant rate of expected growth
27

1 This formula essentially recognizes that the return expected or required by investors is
2 comprised of two factors: the dividend yield (current income) and expected growth in
3 dividends (future income).

4
5 **Q. Please explain how you have employed the DCF model.**

6 A. I have utilized the constant growth DCF model. In doing so, I have combined the current
7 dividend yield for each group of proxy utility stocks described in the previous section with
8 several indicators of expected dividend growth.

9
10 **Q. How did you derive the dividend yield component of the DCF equation?**

11 A. There are several methods that can be used for calculating the dividend yield component.
12 These methods generally differ in the manner in which the dividend rate is employed; i.e.,
13 current versus future dividends or annual versus quarterly compounding of dividends. I
14 believe the most appropriate dividend yield component is the version listed below:

15
16
$$Yield = \frac{D_0(1 + 0.5g)}{P}$$

17

18 This dividend yield component recognizes the timing of dividend payments and dividend
19 increases.

20
21 The P_0 in my yield calculation is the average (of high and low) stock price for each proxy
22 company for the most recent three month period (December 2007 - February 2008). The
23 D_0 is the current annualized dividend rate for each proxy company.

24
25 **Q. How have you estimated the dividend growth component of the DCF equation?**

26 A. The dividend growth rate component of the DCF model is usually the most crucial and
27 controversial element involved in this methodology. The objective of estimating the

1 dividend growth component is to reflect the growth expected by investors that is embodied
2 in the price (and yield) of a company's stock. As such, it is important to recognize that
3 individual investors have different expectations and consider alternative indicators in
4 deriving their expectations. This is evidenced by the fact that every investment decision
5 resulting in the purchase of a particular stock is matched by another investment decision to
6 sell that stock. Obviously, since two investors reach different decisions at the same
7 market price, their expectations differ.

8
9 A wide array of indicators exist for estimating the growth expectations of investors. As a
10 result, it is evident that no single indicator of growth is always used by all investors. It
11 therefore is necessary to consider alternative indicators of dividend growth in deriving the
12 growth component of the DCF model.

13
14 I have considered five indicators of growth in my DCF analyses. These are:

- 15
16 1. 2002-2006 (5-year average) earnings retention, or fundamental growth (per
17 Value Line);
- 18
19 2. 5-year average of historic growth in earnings per share (EPS), dividends
20 per share (DPS), and book value per share (BVPS) (per Value Line);
- 21
22 3. 2007, 2008, and 2010-2012 projections of earnings retention growth (per
23 Value Line);
- 24
25 4. 2004-2006 to 2010-2012 projections of EPS, DPS, and BVPS (per Value
26 Line); and,
27

5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your initial DCF calculations.

A. Schedule 6 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	<u>Mean</u>	<u>Median</u>	<u>Mean High²</u>	<u>Median High²</u>
Proxy Group	9.3%	8.7%	10.4%	9.8%
Hanley Group	8.6%	8.1%	9.3%	9.3%

I note that the individual DCF calculations shown on Schedule 6 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

² Using only the highest growth rate.

1 The DCF results in Schedule 6 indicate average (mean and median) DCF cost rates of 8.1
2 percent to 9.3 percent. The highest DCF rates (i.e., using the highest growth rates only)
3 are 9.3 percent to 10.4 percent.
4

5 **Q. What do you conclude from your DCF analyses?**

6 A. These analyses reflect a broad DCF range of 9.3 percent to 10.4 percent for the proxy
7 groups. This is approximated by the upper portion of the average/mean values, as well as
8 the top DCF calculations for the proxy groups examined in the previous analysis. I give
9 less weight to the lower end of the mean/median results. I believe that 9.3 percent to 10.4
10 percent (9.9 percent mid-point) reflects the proper DCF cost for the proxy groups.
11

12 **IX. CAPITAL ASSET PRICING MODEL ANALYSIS**

13 **Q. Please describe the theory and methodological basis of the capital asset pricing**
14 **model.**

15 A. The CAPM is a version of the risk premium method. The CAPM describes and measures
16 the relationship between a security's investment risk and its market rate of return. The
17 CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory
18 ("MPT"), which studies the relationships among risk, diversification, and expected
19 returns.
20

21 **Q. How is the CAPM derived?**

22 A. The general form of the CAPM is:

23
24
$$K = R_f + \beta(R_m - R_f)$$

25

1 where: K = cost of equity

2 R_f = risk free rate

3 R_m = return on market

4 β = beta

5 $R_m - R_f$ = market risk premium

6
7 As noted previously, the CAPM is a variant of the risk premium method. I believe the
8 CAPM is generally superior to the simple risk premium method because the CAPM
9 specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the
10 simple risk premium method assumes the same risk premium for all companies exhibiting
11 similar bond ratings.

12
13 **Q. What groups of companies have you utilized to perform your CAPM analyses?**

14 A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my
15 DCF analyses.

16
17 **Q. What rate did you use for the risk-free rate?**

18 A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of
19 return that can be achieved without accepting any market risk.

20 In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury
21 securities. Two general types of U.S. Treasury securities are often utilized as the R_f
22 component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

23
24 I have performed CAPM calculations using the three month average yield (December
25 2007 - February 2008) for 20-year U.S. Treasury bonds. Over this three month period,
26 these bonds had an average yield of 4.49 percent.

27

1 **Q. What is beta and what betas did you employ in your CAPM?**

2 A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to
3 the overall market. Betas of less than 1.0 are considered less risky than the market,
4 whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas
5 below 1.0. I utilized the most recent Value Line betas for each company in the groups of
6 proxy utilities.

7
8 **Q. How did you estimate the market risk premium component?**

9 A. The market risk premium component ($R_m - R_f$) represents the investor-expected premium of
10 common stocks over the risk-free rate, or government bonds. For the purpose of
11 estimating the market risk premium, I considered alternative measures of returns of the
12 S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

13
14 First, I have compared the actual annual returns on equity of the S&P 500 with the actual
15 annual yields of U.S. Treasury bonds. Schedule 7 shows the return on equity for the S&P
16 500 group for the period 1978-2006 (all available years reported by S&P). This schedule
17 also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual
18 differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds.
19 Based upon these returns, I conclude that this version of the risk premium is about 6.4
20 percent.

21
22 I have also considered the total returns (i.e., dividends/interest plus capital gains/losses)
23 for the S&P 500 group as well as for the long-term government bonds, as tabulated by
24 Ibbotson Associates, using both arithmetic and geometric means. I have considered the
25 total returns for the entire 1926-2007 period, which are as follows:

	<u>S&P 500</u>	<u>L-T Gov't Bonds</u>	<u>Risk Premium</u>
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.5%	4.9%

I conclude from this that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate because investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 8 shows my CAPM calculations using the risk premium. The results are:

	<u>Mean</u>	<u>Median</u>
Proxy Group	9.7%	9.5%
Hanley Group	9.8%	9.7%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of about 9.5 percent to 9.8 percent for the two groups of comparison utilities.

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of

1 the fair return, because the CE method translates into practice the competitive principle
2 underlying regulation.

3
4 The CE method normally examines the experienced and/or projected returns on book
5 common equity. The logic for examining returns on book equity follows from the use of
6 original cost rate base regulation for public utilities, which uses a utility's book common
7 equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate
8 of return which is then applied (multiplied) to the book value of rate base to establish the
9 dollar level of capital costs to be recovered by the utility. This technique is consistent
10 with the rate base methodology generally used to set utility rates.

11
12 **Q. How have you employed the CE methodology in your analysis of Southwest Gas'**
13 **common equity cost?**

14 A. I conducted the CE methodology by examining realized returns on equity for several
15 groups of companies and evaluating the investor acceptance of these returns by reference
16 to the resulting market-to-book ratios. In this manner, it is possible to assess the degree to
17 which a given level of return equates to the cost of capital. It is generally recognized for
18 utilities that market-to-book ratios of greater than one (i.e., 100 percent) reflect a situation
19 where a company is able to attract new equity capital without dilution (i.e., above book
20 value). As a result, one objective of a fair cost of equity is the maintenance of stock prices
21 above book value.

22
23 I would further note that the CE analysis, as I have employed it, is based upon market data
24 (through the use of market-to-book ratios) and, is thus, essentially a market test. As a
25 result, my analysis is not subject to the criticisms occasionally made by some who
26 maintain that past earned returns do not represent the cost of capital. In addition, my
27 analysis uses prospective returns and thus is not confined to historical data.

1 **Q. What time periods have you examined in your CE analysis?**

2 A. My CE analysis considers the experienced equity returns of the proxy groups of utilities
3 for the period 1992-2006 (i.e., past fifteen years). The CE analysis requires that I examine
4 a relatively long period of time in order to determine trends in earnings over at least a full
5 business cycle. Further, in estimating a fair level of return for a future period, it is
6 important to examine earnings over a diverse period of time in order to avoid any undue
7 influence from unusual or abnormal conditions that may occur in a single year or shorter
8 period. Therefore, in forming my judgment of the current cost of equity I have focused on
9 two periods: 2002-2006 (the past five years - the average length of a business cycle) and
10 1992-2001 (the most recent complete business cycle).

11
12 **Q. Please describe your CE analysis.**

13 A. Schedules 9 and 10 contain summaries of experienced returns on equity for several groups
14 of companies, while Schedule 11 presents a risk comparison of utilities versus unregulated
15 firms.

16 Schedule 9 shows the earned returns on average common equity and market-to-book ratios
17 for the two groups of proxy utilities. These can be summarized as follows:

18
19

Group	Historic		Prospective
	ROE	M/B	ROE
Proxy Group	11.9-13.1%	180-195%	12.0-12.4%
Hanley Group	12.0-12.3%	180-184%	11.6-11.9%

20
21
22

23 These results indicate that historic returns of 11.9-13.1 percent have been adequate to
24 provide market-to-book ratios of 180-195 percent for the groups of proxy utilities.
25 Furthermore, projected returns on equity for 2007, 2008, and 2010-2012 are within a
26 range of 11.6 percent to 12.4 percent for the utility groups. These relate to 2006 market-
27 to-book ratios of 191 percent or higher.

1 **Q. Have you also reviewed earnings of unregulated firms?**

2 A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have
3 examined the Standard & Poor's 500 Composite group, because this is a well recognized
4 group of firms that is widely utilized in the investment community and is indicative of the
5 competitive sector of the economy. Schedule 10 presents the earned returns on equity and
6 market-to-book ratios for the S&P 500 group over the past fifteen years. As this Schedule
7 indicates, over the two periods this group's average earned returns ranged from 14.1-14.7
8 percent with market-to-book ratios ranging between 284 percent and 341 percent.

9
10 **Q. How can the above information be used to estimate the cost of equity for Southwest**
11 **Gas?**

12 A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an
13 indication of the level of return realized and expected in the regulated and competitive
14 sectors of the economy. In order to apply these returns to the cost of equity for proxy
15 utilities, however, it is necessary to compare the risk levels of the utility industry with
16 those of the competitive sector. I have done this in Schedule 11, which compares several
17 risk indicators for the S&P 500 group and the utility groups. The information in this
18 schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

19
20 **Q. What return on equity is indicated by the CE analysis?**

21 A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis
22 indicates that the cost of equity for the proxy utilities is no more than 10.0 percent to 10.5
23 percent (10.25 percent mid-point). Recent returns of 11.8-13.1 percent have resulted in
24 market-to-book ratios of 180 and greater. Prospective returns of 11.6 percent to 12.4
25 percent result in anticipated market-to-book ratios of 190 percent or over. As a result, it is
26 apparent that returns below this level would result in market-to-book ratios of well above
27 100 percent. Accordingly, an earned return of 10.0 percent to 10.5 percent should result in

1 a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-
2 book ratios substantially exceed 100 percent indicates that historic and prospective returns
3 of 10 percent to 11 percent reflect earnings levels that exceed the cost of equity for those
4 regulated companies.

5
6 In applying the CE analysis, it also is important to recognize recent trends. My
7 recommended range of 10.0 percent to 10.5 percent is further supported by the actual
8 newly authorized returns on common equity from 2002 through June 2007, which are as
9 follows for U.S. natural gas utilities as authorized by state regulatory agencies:

<u>Year</u>	<u>ROE</u>	<u>No. of Decisions</u>
2002	11.03%	21
2003	10.99%	25
2004	10.59%	20
2005	10.46%	26
2006	10.43%	16
2007 (6 months)	10.34%	15

18 Source: Regulatory Research Associates, "Regulatory Focus" July 3, 2007.

19
20 Please also note that my CE analysis is not based on a mathematic formula approach, as
21 are the DCF and CAPM methodologies. Rather, it is based on recent trends and current
22 conditions in equity markets. Further, it is based on the direct relationship between
23 returns on common stock and market-to-book ratios of common stock. In utility rate
24 setting, a fair rate of return is generally based on the utility's assets (i.e., rate base) and the
25 book value of the utility's capital structure. As stated earlier, maintenance of a financially
26 stable utility's market-to-book ratio at 100 percent, or a bit higher, is fully adequate to
27 maintain the utility's financial stability. On the other hand, a market price of a utility's
28 common stock that is 150 percent or more above the stock's book value is indicative of
29 earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected

1 earnings do not directly translate into a utility's reasonable cost of equity. Rather, they
2 must be viewed in relation to the market-to-book ratios of the utility's common stock.

3
4 My 10.0 percent to 10.5 percent CE recommendation reflects the fact that historic equity
5 returns of 11.9 percent to 13.1 percent have resulted in market-to-book ratios of 180
6 percent to 195 percent, which demonstrates that the equity returns exceed the cost of
7 capital. Likewise, projected returns of about 11.6 percent to 12.6 percent relate to 2006
8 market-to-book ratios of 190 percent and over. My 10.0 percent to 10.5 percent CE
9 recommendation is not designed to result in market-to-book ratios as low as 1.0 for
10 Southwest Gas. Rather, it is based on current market conditions and the proposition that
11 ratepayers should not be required to pay rates based on earnings levels that result in
12 excessive market-to-book ratios.

13
14 **XI. RETURN ON EQUITY RECOMMENDATION**

15 **Q. Please summarize the results of your three cost of equity analyses.**

16 **A.** My three methodologies produce the following:

17		
18	Discounted Cash Flow	9.3-10.4%
19	Capital Asset Pricing Model	9.5-9.8%
20	Comparable Earnings	10.0-10.5%

21 My overall conclusion from these results is a reasonable range of 9.3 percent to 10.5
22 percent, which focuses on the respective individual model findings. The mid-point of this
23 range is 9.9 percent.

24

1 **Q. What cost of equity do you recommend for Southwest Gas?**

2 A. I recommend a cost of equity of 10.0 percent, which is slightly above the 9.9 percent mid-
3 point of my cost of equity range. I recommend a slightly higher cost of equity to reflect
4 the lower equity ratio and lower debt ratings of Southwest Gas versus the proxy groups.

5
6 **XII. TOTAL COST OF CAPITAL**

7 **Q. What is the total cost of capital for Southwest Gas?**

8 A. Schedule 1 reflects the total cost of capital for the Company using the actual capital
9 structure and costs of short-term debt, long-term debt and preferred stock, and my
10 common equity cost recommendations. The resulting total cost of capital is a range of
11 8.55 percent to 9.07 percent (8.86 percent with 10.0 percent cost of equity). I recommend
12 that this 8.86 percent total cost of capital be established for Southwest Gas.

13
14 **Q. Does your cost of capital recommendation provide the company with a sufficient**
15 **level of earnings to maintain its financial integrity?**

16 A. Yes, it does. Schedule 12 shows the pre-tax coverage that would result if Southwest Gas
17 earned my cost of capital recommendation. As the results indicate, my recommended
18 range would produce a coverage level within the benchmark range for a Triple B rated
19 utility. In addition, the debt ratio (which reflects the Company's proposed capital
20 structure) is within the benchmark for a Triple B rated utility.

21
22 **XIII. COMMENTS ON COMPANY TESTIMONY**

23 **Q. Have you reviewed the cost of capital testimony of Southwest Gas witness Frank J.**
24 **Hanley?**

25 A. Yes, I have.
26

Q. What is your understating of his cost of capital recommendation for Southwest Gas?

A. Mr. Hanley is recommending a total cost of capital for Southwest Gas of 9.45 percent, as follows:

	Ratios */	Cost	Weighted Cost
Long-Term Debt	51.0%	7.96%	4.06%
Preferred Stock	4.0%	8.20%	0.33%
Common Equity	45.0%	11.25%	5.06%
			9.45%

*/ April 30, 2007 cost rates applied to a hypothetical capital structure.

Q. How does he derive his cost of equity recommendation?

A. Mr. Hanley performs the following cost of equity analyses and derives the indicated results:

	Southwest Gas	Proxy Group of 8 Value Line LDCs
Discounted Cash Flow	NMF	9.92%
Risk Premium	10.86%	10.96%
Capital Asset Pricing Model	10.28%	10.50%
Comparable Earnings	13.42%	13.88%
Indicated Cost of Equity	11.00%	11.00%
Investment Risk Adjustment	--	0.31%
Recommended Cost of Equity	11.00%	11.31%

His recommendation for Southwest Gas is 11.25 percent.

Q. Do you have any disagreements with any or all of Mr. Hanley's methodologies and recommendations?

A. Yes, I have disagreements with each of his cost of equity methodologies and conclusions, as well as his proposed 0.31 percent "investment risk adjustment" for Southwest Gas. I note that, even though Mr. Hanley claims (page 7, lines 4-5) his methodologies and

1 conclusions are predicated on the Efficient Market Hypothesis ("EMH"), many of the
2 "adjustments" he makes to the models are in violation of the EMH.
3

4 **Q. Please begin with his DCF model and conclusions.**

5 A. Mr. Hanley's 9.92 percent DCF conclusion is shown on Exhibit ____ (FJH-6). It is
6 apparent from his exhibit that Mr. Hanley only considers the DCF results of two of the
7 eight companies in his proxy group due to his exclusion of all DCF rates of 9.6 percent or
8 less, which he rationalizes as "the lowest rate awarded to a gas distribution utility during
9 the twelve months ended March 2007." I do not believe it is appropriate to exclude
10 virtually all of his DCF results for this reason. I also note that the currently authorized
11 return on equity for Southwest Gas is less than 9.6 percent.
12

13 **Q. Mr. Hanley maintains in his testimony on pages 8 and 24-28, that the DCF model**
14 **cannot be used as an estimate of the cost of equity for a utility when the market price**
15 **of utility stocks exceeds the book value. Do you agree with this position?**

16 A. No, I do not. Knowledgeable and/or informed investors are aware of the fact that most
17 utilities have their rates set based on the book value of their assets (i.e., rate base and
18 capital structure). This knowledge is reflected in the prices that investors are willing to
19 pay for stocks and thus is reflected in DCF cost rates. To make a modification of the DCF
20 cost rates, as Mr. Hanley proposes, amounts to an attempt to "reprice" stock values in
21 order to develop a DCF cost rate more in line with what he thinks the results should be.
22 This is clearly a violation of the principle of "the EMH", which Mr. Hanley cites
23 extensively in his testimony. If one believes that markets are efficient, there is no reason
24 to modify either stock prices or market models based on stock prices.
25

1 **Q. On page 26, Mr. Hanley states his view that when market prices exceed the book**
2 **value, the DCF results understate the cost of equity. He also postulates that when the**
3 **reverse occurs, the DCF results would overstate the cost of capital. Do you have any**
4 **comments on this?**

5 A. Yes, I do. I was testifying in utility rate cases in the 1970s and early 1980s, a period
6 during which utility stock prices were frequently well below book value. Based on my
7 personal recollections, I cannot remember a single instance in which a utility-sponsored
8 cost of capital witness advocated that the DCF model overstated the cost of equity. I also
9 never have taken this position.

10
11 I also note that I testified in a large number of rate proceedings in which Mr. Hanley and
12 members of his firm testified. I can recall of no instances in which any AUS witness
13 testified that the DCF result overstated the cost of equity.

14
15 **Q. Please describe Mr. Hanley's risk premium methodology and conclusions.**

16 A. Mr. Hanley's risk premium methodology combines his estimate (6.6 percent) of the
17 prospective yield on A rated public utility bonds, adjusted by 0.40 percent (for Southwest
18 Gas) and 0.09 percent (for proxy group) to reflect lower debt ratings with "equity risk
19 premiums" of 3.86 percent and 4.27 percent to arrive at a risk premium cost of equity of
20 10.86 percent to 10.96 percent.

21
22 **Q. Do you agree with his methodology and conclusions?**

23 A. No, I do not. I note, first, that recent yields on A rated utility bonds are below the 6.60
24 percent used by Mr. Hanley. This indicates that his "prospective" yields were overstated.
25 I also disagree with the equity risk premium level of 3.86 percent to 4.27 percent he
26 employs. Mr. Hanley uses two studies to derive this risk premium and averages the two
27 results. First, he compares total returns for the S&P over the 1926-2006 period with yields

1 on corporate bonds over the same period, as well as forecasted total returns on stocks
2 versus prospective yields on corporate bonds to derive an equity risk premium of 6.20
3 percent. He then multiplies the average by the betas of his LDC proxy groups (in a
4 CAPM context) to develop his 4.14 percent to 4.29 percent equity risk premium. Use of
5 total returns over the 1926-2006 period, in connection with bond yields over the same long
6 period, does not imply that any such relationships are expected by investors in 2008.
7 First, his methodology is a mis-match since it compares holding period returns (i.e.,
8 capital gains/losses plus income) with yields on bonds (i.e., only income). In addition, the
9 1926-2006 period was heavily influenced by the Great Depression, World War II, the high
10 inflation/interest rate environment of the 1970s/1980s, etc. Such factors are not prevalent
11 currently and have the effect of inflating risk premiums over those expected by investors.
12 I believe Mr. Hanley's analyses over-state the required risk premiums at the present time.
13 The fact that Mr. Hanley's forecasted equity risk premium is some two hundred and sixty
14 basis points less than the historic risk premium is further indication of this concern.

15
16 In addition, I find it inconsistent on his part to defend use of historic data going back to
17 1926 in his risk premium and CAPM analyses, and to then ignore historic data in his DCF
18 analyses. I do not see how an investor would place equal weight between returns in 1926
19 and 2006 in one type of analysis (i.e., risk premium and CAPM) and then give no weight
20 whatsoever to recent (i.e., 5 years) experience in DCF analysis.

21
22 **Q. Please describe Mr. Hanley's CAPM analyses.**

23 **A.** Mr. Hanley performs two CAPM analyses. His first CAPM is a "traditional" CAPM,
24 where he concludes that 10.17 percent to 10.49 percent is the CAPM cost. This uses a risk
25 free rate of 5.33 percent (projected yield on 30-year U.S. Treasury bonds). Actual 30-year
26 Treasury bonds have recently yielded below 4.5 percent, which indicates that his
27 prospective yield was excessive.

1 Mr. Hanley also performs an "empirical" CAPM analysis, wherein he assigns 75 percent
2 weight to actual betas for the proxy groups of gas utilities and a 25 percent weight to an
3 assumed beta of 1.0 (i.e., the market beta). I disagree with this empirical CAPM.

4
5 The use of an empirical CAPM overstates the cost of equity for companies with betas
6 below that of the market. What the empirical CAPM actually does is inflate the CAPM
7 cost for the selected company or industry on one-fourth of its equity and assumes that one-
8 fourth of the company has the risk of the overall market. This is not appropriate for
9 Southwest Gas or for other utilities because it essentially creates a hypothetical beta that is
10 used in the place of the actual beta. Investors are provided actual betas by organizations
11 such as Value Line and it is reasonable to believe that investors rely upon these betas to
12 some extent in making investment decisions. Mr. Hanley has provided no rationale or
13 reasons to believe that investors would ignore these published betas and instead rely on
14 hypothetical betas that are neither published nor readily available.

15
16 **Q. Mr. Hanley also maintains that the traditional CAPM understates the cost of equity**
17 **for companies with betas below 1.0. Do you agree with his position?**

18 A. No, I do not. Again, Mr. Hanley fails to accept the fact that betas are determined using
19 actual stock price movements and reflect actual decisions by investors. If one accepts the
20 Efficient Market Hypothesis, as he does, there is no reason to modify the actual stock
21 price movements and substitute alternative movements, as the empirical CAPM does.

22
23 **Q. Please summarize Mr. Hanley's comparable earnings method.**

24 A. Mr. Hanley's comparable earnings analysis examines the forecasted returns on equity for
25 two groups of 23 and 34 non-utility companies which he perceives as being of similar risk
26 to Southwest Gas and his LDC proxy group. For the 23 companies, he calculated a 5-year

1 forecasted return of 13.42 percent. The corresponding number for the group of 34
2 companies is 13.88 percent.

3
4 I believe this analysis is an improper mechanism for estimating the cost of common equity
5 for Southwest Gas. The equivalence of beta values (i.e., the basis for his selection of
6 comparison companies) does not indicate that the expected earnings and cost of common
7 equity for these non-utilities and utilities are the same. The projected 3-5 year returns for
8 the non-utilities is 13.42 and 13.88 percent in Mr. Hanley's Exhibit___(FTH-13) whereas
9 the respective returns for Mr. Hanley's proxy group of LDC utility companies is only
10 11.6-11.9 percent (my Schedule 9). This difference in returns demonstrates that utilities
11 are able to maintain similar Value Line betas to non-utilities even though their expected
12 earnings are substantially lower than those of the non-utilities. This result indicates that
13 the expected earnings for the non-utilities are greater than for utilities such as Southwest
14 Gas.

15
16 **Q. Mr. Hanley concludes that the "indicated cost of equity" for his proxy group is 11.0**
17 **percent, which he increases by some 0.31 percent to reflect his perception of a**
18 **required "investment risk adjustment" for Southwest Gas. What is your response to**
19 **this proposed adjustment?**

20 **A.** I disagree with Mr. Hanley's proposed investment risk adjustment for Southwest Gas. Mr.
21 Hanley's 0.31 percent investment risk adjustment (which forms the basis for his 11.25
22 percent recommendation, which actually incorporates a 0.25 percent adjustment for
23 Southwest Gas) is based on the yield differentials between A rated utility bonds and BBB
24 rated utility bonds (see page 54, lines 6-8 and Sheet 3 of Mr. Hanley's FJH-1). Mr.
25 Hanley is maintaining that, since Southwest Gas has lower debt ratings than his proxy
26 group, the Company's cost of equity should be higher than that for the proxy group by the
27 same differential as the yield differential between A rated and BBB rated utility bonds.

28
29 I do not believe that Mr. Hanley's proposed financial risk adjustment is warranted. As I
30 noted in an earlier section of my testimony, Southwest Gas has historically maintained a

1 lower equity ratio than most gas distribution utilities, which clearly has been a significant
2 factor its lower bond ratings. In addition, during much of the late 1980s and 1990s,
3 Southwest Gas owned a savings bank, which was a negative influence on the Company's
4 financial performance and security ratings. Neither of these factors presently exist for
5 Southwest Gas. The Company's common equity ratio is now similar to other gas
6 distribution utilities and the savings bank has been sold. It does appear, however, that the
7 lingering effects of these factors still influence the Company's ratings, especially the
8 historically lower equity ratios.

9
10 As a result, I do not believe it is appropriate to add the full 0.31 percent (or 0.25 percent)
11 differential to establish the cost of equity for Southwest Gas. I note, further, that Mr.
12 Hanley's own analyses show the same "indicated common equity cost rate before
13 investment risk adjustments" as shown on his FJH-1, page 2, which indicates the same
14 cost rate for Southwest Gas and his proxy group.

15
16 **XIV. FAIR VALUE RATE BASE COST OF CAPITAL**

17 **Q. What is your understanding of Southwest Gas' position on the issue of fair value rate**
18 **base and related cost of capital implications?**

19 A. It is my understanding that Southwest Gas is requesting that the fair value of its rate base
20 be used in developing its rates. The Company does not appear to be requesting that its
21 weighted cost of capital be applied to the level of its fair value rate base.

22
23 **Q. What is your understanding of the Commission's procedure for utilizing the fair**
24 **value of rate base in setting utility rates?**

25 A. My "non-legal understanding" is that the Commission must consider the fair value of a
26 utility's assets in setting rates. However, I do not agree that this implies that the
27 Company's cost of capital must be applied to the fair value of the rate base.

1 **Q. Are you aware that the Commission has recently conducted a “remand” hearing on**
2 **the issue of regulatory treatment of fair value rate base for Chaparral City Water**
3 **Company?**

4 A. Yes, I am. In January of this year, the Commission conducted a public hearing in
5 response to a remand by the Arizona Appeals Court (Appeals No. CA-CC 05-002)
6 decision³ in Chaparral City Water Company (Docket No. W-02113A-04-0616). The
7 purpose of this hearing was to determine the appropriate cost of capital to be applied to an
8 Arizona utility’s fair value rate base.

9
10 **Q. What is your understanding of the use of fair value rate base in Arizona?**

11 A. My “non-legal understanding” is based in part on the 2006 Arizona Court of Appeals
12 decision⁴ in the Chaparral City case (Docket No. 02113A-04-0616), that indicates that the
13 Court agreed with the Commission that “the cost of capital analysis ‘is geared to concepts
14 of original cost measures of rate base, not fair value measures of rate base’” The
15 decision goes on to make the following statement: “If the Commission determines that the
16 cost of capital analysis is not the appropriate methodology to determine the rate of return
17 to be applied to the FVRB, the Commission has the discretion to determine the appropriate
18 methodology.” It is correspondingly the purpose of this section of my testimony to
19 recommend an “appropriate methodology” for use in conjunction with a FVRB.

20
21 **Q. Do you have any observations based upon your own experience in cost of capital**
22 **determination, as to whether a cost of capital developed for application to an original**
23 **cost rate base is consistent with a fair value rate base?**

24 A. Yes, I do. It is my personal experience, based upon over 35 years of providing cost of
25 capital testimony, that the concept of cost of capital is designed to apply to an original cost
26 rate base. This is the case since the cost of capital is derived from the liabilities/owners’

³ CA-CC 05-0002, Memorandum Decision dated February 13, 2007.

⁴ CA-CC 05-0002, Memorandum Decision dated February 13, 2007.

1 equity side of a utility's balance sheet using the book values of the capital structure
2 components. The cost of capital, once determined, is then applied to (i.e., multiplied by)
3 the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From
4 a financial perspective, the rationale for this relationship is that the rate base is financed by
5 the capitalization. Under this relationship, a provision is provided for investors (both
6 lenders and owners) to receive a return on their invested capital. Such a relationship is
7 meaningful as long as the cost of capital is applied to the original cost (i.e., book value)
8 rate base, because there is a matching of rate base and capitalization.

9
10 When the concept of fair value rate base is incorporated, however, this link between rate
11 base and capital structure is broken. The amount of fair value rate base that exceeds
12 original cost rate base is not financed with investor-supplied funds and, indeed, is not
13 financed at all. As a result, a customary cost of capital analysis cannot be automatically
14 applied to the fair value rate base since there is no financial link between the two concepts.
15 In my "non-legal" opinion, both the Commission and Appeals Court have also recognized
16 this lack of compatibility between a customary weighted cost of capital ("WCOC")
17 analysis and FVRB.

18
19 **Q. Why is it important that there be a link between the concepts of rate base and cost of**
20 **capital?**

21 A. This link is important since financial theory indicates that investors should be provided an
22 opportunity to earn a return on the capital they provided to the utility. Since the capital
23 finances the rate base (in an original cost world), the link between cost of capital and rate
24 base satisfies this financial objective.

25

Q. Based on your experience as a cost of capital witness over the past 35 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for Southwest Gas?

A. Yes, I do. Since the increment between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to Southwest Gas' FVRB.

Item	Amount	Percent	Cost	Fair Value Return
Short-term Debt ⁵	\$0	0.00%		
Long-term Debt	557,641,284	40.01%	7.96%	3.18%
Preferred Stock	47,969,143	3.44%	8.20%	0.28%
Common Equity	465,129,366	33.37%	10.0%	3.34%
FVRB Increment ⁶	323,152,085	23.18%	0.00%	0.00%
Total FVRB Capital	\$1,393,891,878	100.00%		6.80%

Applying this 6.80 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB.

⁵ As is the case for my cost of capital calculations, no short-term debt is included since the Company had none at the end of the test period.

⁶ FVRB minus OCRB.

1 **Q. Have you developed an alternative method with which to apply a FVROR to a**
2 **FVRB?**

3 A. Yes, I have. Should the Commission determine that there should be a specific return
4 (greater than zero) applied to the FVRB Increment, I have provided such a procedure.
5

6 **Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the**
7 **OCRB?**

8 A. The WCOC authorized by the Commission has already provided for a full cost of equity
9 return and cost of debt on the portions of equity and debt capital that are supporting the
10 OCRB portion of the FVRB. As a result, there is no need to provide any additional return
11 on the portions of FVRB supported by common equity and debt.
12

13 Stated differently, both the cost of debt and the return on common equity (i.e., capital
14 stock, paid-in capital, and retained earnings - the investment of common shareholders) are
15 already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds
16 OCRB ("Fair Value Increment") needs to have a specific return identified in order to
17 reflect a return component on that Fair Value Increment.
18

19 **Q. What is the proper cost rate to apply to the Fair Value Increment?**

20 A. As I indicated previously, from a financial perspective, it should not be necessary to
21 provide for any return on the Fair Value Increment since this is not investor-supplied
22 capital. However, the Commission may choose to evaluate this issue from both a financial
23 and a public policy perspective. I am aware that Southwest Gas may claim that the
24 concept of fair value carries with it the notion that investors should receive some benefit
25 when fair value is greater than original cost and should suffer some detriment when fair
26 value is less than original cost. It is possible that the Commission may determine that
27 Arizona's fair value provision, which is somewhat unique, is not inconsistent with these

1 concepts. Nonetheless, the idea that the Company should receive some benefit from the
2 Fair Value Increment does not mean that one should automatically apply to the FVRB a
3 WCOC developed by reference to original cost rate base. If it is determined that it is
4 desirable to provide an additional (non-zero) return on the Fair Value Increment, the
5 proper return should be no larger than the real (i.e., after inflation is removed) risk-free
6 rate of return.

7
8 **Q. What is the risk-free return?**

9 A. The risk-free return is, in financial terms, the return on an investment that carries little or
10 no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with
11 short-term maturities usually being used as the risk-free rate. Over the past several
12 months, various maturities of U.S. Treasury securities have yielded from about 2.0 percent
13 (short-term) to 4.5 percent (long-term) in nominal terms. Rates have declined recently. I
14 also note that 2008-2009 forecasts of U.S. Treasury securities are about 4.0 percent to 4.5
15 percent. As a result, I use 4.5 percent as the nominal risk-free rate.

16
17 **Q. What is the "real" risk-free rate?**

18 A. The concept of real rates involves the removal of the rate of inflation from the nominal
19 risk-free rate. In 2007, the rate of inflation, as measured by the Consumer Price Index
20 ("CPI"), was 4.1 percent. Forecasts of the CPI for 2008-2009 are about 2 percent. As a
21 result, I propose to use a 2 percent inflation rate for computing the real risk-free rate,
22 which is computed as follows:

23

24	Nominal Risk-Free Rate	4.5%
25	Less: Inflation Rate	2.0%
26	Equals: Real Risk-Free Rate	2.5%

27

1 **Q. Please explain why Southwest Gas' FVROR should consider the real risk-free rate,**
2 **as opposed to the nominal risk-free rate.**

3 A. The investors of Southwest Gas are already receiving an inflation factor due to the
4 inclusion of inflation in the FVRB Increment. Specifically, the Fair Value Increment
5 incorporates inflation by considering the current value of assets, which reflect, in part, past
6 inflation. It would be double-counting to also include the inflation components in the
7 return to be applied to the FVRB Increment.

8
9 **Q. What return on the Fair Value Increment do you recommend in your alternative**
10 **FVROR proposal?**

11 A. My alternative FVROR proposal incorporates a return on the Fair Value Increment with a
12 maximum value of 2.5 percent, as developed above. However, I wish to emphasize that
13 this 2.5 percent value is the maximum value that could be applied to the FVRB Increment.
14 In reality, any value between zero percent and 2.5 percent could be used as the cost rate on
15 the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to
16 the return that the Company's investors already earn on their investment in the Company.
17 In this sense, an above-zero cost rate for the fair value increment represents a bonus to the
18 Company that would have to find its justification in policy considerations instead of in
19 pure economic or financial principles; for that reason, the selection of an appropriate cost
20 rate within this range should fall to the Commission's discretion. I would propose the
21 mid-point of this range, or 1.25 percent.

22
23 **Q. What is the resulting impact of your alternative proposal in this proceeding?**

24 A. I am proposing the following modified FVROR for Southwest Gas:
25

Capital Item	Percent	Cost	Return
Short-term Debt	0.00%		
Long-term Debt	40.07%	7.96%	3.18%
Preferred Stock	3.44%	8.20%	0.28%
Common Equity	33.37%	10.00%	3.34%
FVRB Increment	23.18%	1.25%	0.29%
Total	100.00%		7.09%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of Southwest Gas, and provides for an overall fair value rate of return of 7.09 percent on the FVRB.

Q. Of the two alternative proposals for determining the fair value rate of return that should be applied to the FVRB, which one do you believe is more appropriate and why?

A. From a financial perspective, I believe the first proposal (i.e., zero-cost for FVRB Increment) is most appropriate. This proposal is consistent with financial principles and would fully compensate the Company's investors for their investment. In addition, this proposal utilizes the FVRB of the Company. If the Commission were to determine that a non-zero return on the Fair Value Increment is desirable, the alternative (i.e., a 1.25% cost-rate for the FVRB increment) is not inappropriate.

Q. Do these proposals provide for a return on the FVRB of Southwest Gas?

A. Yes, they do.

Q. Will Staff continue to evaluate appropriate methods for determining the fair value rate of return on fair value rate base?

A. It is my understanding that the Commission Staff will continue to consider these issues in the context of future rate cases. Individual rate cases present different issues and varying sets of circumstances. For example, if one were to assign a non-zero cost rate to the fair

1 value increment, it may be appropriate to determine the cost of equity to reflect a
2 reduction in risk. I have not proposed such an adjustment in this case, but these issues may
3 appear as Staff continues to consider appropriate methods for determining and evaluating
4 the concept of fair value rate of return on fair value rate base.

5

6 **Q. Does this conclude your Direct Testimony?**

7 **A. Yes.**

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a

commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts
 Board of Directors 1992-2000
 Secretary/Treasurer 1994-1998
 President 1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial

Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review, Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

**SOUTHWEST GAS CORP.
TOTAL COST OF CAPITAL**

Item	Amount	Percent	Cost	Weighted Cost
Short-Term Debt	\$0	0.00%		0.00%
Long-Term Debt	\$1,163,505,877	52.08%	7.96%	4.15%
Preferred Stock	\$100,000,000	4.48%	8.20%	0.37%
Common Equity	\$970,385,472	43.44%	9.30%	10.50%
				4.04%
				4.56%
Total	\$2,233,891,349	100.00%		8.55%
				9.07%
				8.86%
				With 10.0% ROE

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Unemploy- ment Rate	Consumer Price Index	Producer Price Index
1975 - 1982 Cycle					
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
1983 - 1991 Cycle					
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
1992 - 2001 Cycle					
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.7%	4.2%	2.7%	2.9%
2000	3.7%	4.5%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
Current Cycle					
2002	1.6%	0.0%	5.8%	2.4%	1.2%
2003	2.5%	1.1%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	3.1%	3.2%	5.1%	3.4%	5.4%
2006	2.9%	3.9%	4.6%	2.5%	1.1%
2007	2.2%	2.1%	4.6%	4.1%	6.3%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Unemploy- ment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.8%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	4.5%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.2%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	4.8%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	1.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	2.1%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.6%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.8%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	4.9%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	0.6%	1.7%	4.8%	5.6%	12.8%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1975 - 1982 Cycle							
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
1983 - 1991 Cycle							
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
1992 - 2001 Cycle							
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
Current Cycle							
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003							
Jan	4.25%	1.17%	4.05%	[1]	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
1975 - 1982 Cycle					
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
1983 - 1991 Cycle					
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
1992 - 2001 Cycle					
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
Current Cycle					
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

**SOUTHWEST GAS CORP
BOND RATINGS**

<u>Date</u>	<u>Moody's</u>	<u>Standard & Poor's</u>	<u>Fitch</u>
1995	Baa3	BBB-	
1996	Baa2	BBB-	
1997	Baa2	BBB-	
1998	Baa2	BBB-	
1999	Baa2	BBB-	
2000	Baa2	BBB-	BBB
2001	Baa2	BBB-	BBB
2002	Baa2	BBB-	BBB
2003	Baa2	BBB-	BBB
2004	Baa2	BBB-	BBB
2005	Baa2	BBB-	BBB
2006	Baa3	BBB-	BBB
2007	Baa3	BBB-	BBB

Source: Response to Request No. STF-2-6.

**SOUTHWEST GAS CORP.
CAPITAL STRUCTURE RATIOS
2002 - 2007
(\$000)**

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2003	\$630,467 33.0% 34.0%	\$1,221,164 63.9% 66.0%	\$58,435 3.1%
2004	\$705,676 35.8% 35.8%	\$1,262,936 64.2% 64.2%	0.0%
2005	\$751,135 34.4% 36.2%	\$1,324,898 60.7% 63.8%	\$107,215 4.9%
2006	\$901,425 38.9% 39.4%	\$1,386,354 59.9% 60.6%	\$27,545 1.2%
2007	\$983,673 41.0% 41.9%	\$1,366,067 57.0% 58.1%	\$47,079 2.0%

Note: Percentages may not total 100.0% due to rounding.

Source: Southwest Gas Corp., Annual Reports to Stockholders.

VALUE LINE GAS DISTRIBUTION COMPANIES
COMMON EQUITY RATIOS

COMPANY	2000	2001	2002	2003	2004	2005	2006	Average	2009-2011
AGL Resources	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	46.0%	51.5%
Atmos Energy	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	47.9%	49.0%
Energen	53.1%	46.9%	53.2%	55.8%	56.7%	56.6%	67.4%	55.7%	60.0%
Laclede Group	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	51.0%	51.0%
New Jersey Resources	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	56.7%	72.8%
NICOR	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	62.8%	74.0%
Northwest Natural Gas	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	52.4%	52.0%
Piedmont Natural Gas	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	55.3%	50.8%
South Jersey Industries	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	47.1%	59.0%
Southwest Gas	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	36.4%	47.0%
UGI	19.1%	17.4%	21.7%	33.0%	35.0%	41.7%	35.9%	29.1%	67.0%
WGL Holdings	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	61.5%	56.4%	65.8%
Average	48.3%	45.7%	47.4%	50.4%	51.4%	51.9%	53.1%	49.7%	58.3%
Composite			41.4%	43.7%	45.7%	48.3%		44.8%	46.0%

Source: Value Line Investment Survey.

**COMPARISON COMPANIES
CAPITAL STRUCTURE RATIOS
INCLUDING SHORT-TERM DEBT**

Company	2001	2002	2003	2004	2005	2006
AGL Resources	32%	33%	41%	41%	41%	42%
Atmos Energy	40%	39%	45%	41%	38%	45%
Energen	45%	47%	55%	51%	56%	64%
Laclede Group	41%	37%	37%	40%	38%	58%
New Jersey Resources	43%	44%	44%	45%	43%	51%
NICOR	50%	51%	41%	43%	42%	51%
Northwest Natural Gas	46%	48%	50%	49%	47%	48%
Piedmont Natural Gas	51%	54%	53%	53%	48%	46%
South Jersey Industries	32%	34%	41%	31%	45%	44%
Southwest Gas	31%	33%	33%	34%	36%	41%
UGI	14%	24%	29%	31%	33%	32%
WGL Holdings	48%	48%	49%	52%	58%	51%
Average	39%	41%	43%	43%	44%	48%

Source: AUS Utility Reports.

**COMPARISON COMPANIES
DIVIDEND YIELD**

COMPANY	DPS	November, 2007 - January, 2008			YIELD
		HIGH	LOW	AVERAGE	
Value Line Natural Gas Distribution Companies					
AGL Resources	\$1.64	\$39.21	\$35.42	\$37.32	4.4%
Atmos Energy	\$1.30	\$28.85	\$26.00	\$27.43	4.7%
Energen	\$0.46	\$70.41	\$57.61	\$64.01	0.7%
Laclede Group	\$1.50	\$35.72	\$31.86	\$33.79	4.4%
New Jersey Resources	\$1.60	\$52.07	\$43.83	\$47.95	3.3%
NICOR	\$1.86	\$45.16	\$37.40	\$41.28	4.5%
Northwest Natural Gas	\$1.50	\$50.89	\$44.62	\$47.76	3.1%
Piedmont Natural Gas	\$1.00	\$27.98	\$24.01	\$26.00	3.8%
South Jersey Industries	\$1.08	\$38.50	\$33.82	\$36.16	3.0%
Southwest Gas	\$0.86	\$30.97	\$26.30	\$28.64	3.0%
UGI	\$0.74	\$28.18	\$23.99	\$26.09	2.8%
WGL Holdings	\$1.37	\$34.62	\$31.31	\$32.97	4.2%
Average					3.5%
Hanley Proxy Companies					
AGL Resources	\$1.64	\$39.21	\$35.42	\$37.32	4.4%
Atmos Energy	\$1.30	\$28.85	\$26.00	\$27.43	4.7%
Laclede Group	\$1.50	\$35.72	\$31.86	\$33.79	4.4%
NICOR	\$1.86	\$45.16	\$37.40	\$41.28	4.5%
Northwest Natural Gas	\$1.50	\$50.89	\$44.62	\$47.76	3.1%
Piedmont Natural Gas	\$1.00	\$27.98	\$24.01	\$26.00	3.8%
South Jersey Industries	\$1.08	\$38.50	\$33.82	\$36.16	3.0%
WGL Holdings	\$1.37	\$34.62	\$31.31	\$32.97	4.2%
Average					4.0%

Source: Yahoo! Finance.

**COMPARISON COMPANIES
RETENTION GROWTH RATES**

COMPANY	2002	2003	2004	2005	2006	Average	2007	2008	'10-'12	Average
Value Line Natural Gas										
AGL Resources	7.0%	6.6%	5.6%	6.2%	6.3%	6.3%	5.0%	6.0%	6.0%	5.7%
Atmos Energy	1.9%	2.8%	1.7%	2.3%	3.6%	2.5%	3.0%	3.0%	4.0%	3.3%
Energen	7.0%	12.1%	12.4%	16.1%	16.7%	12.9%	19.0%	16.5%	12.5%	16.0%
Laclede Group	0.0%	3.1%	2.7%	3.1%	5.1%	2.8%	4.0%	3.5%	4.0%	3.8%
New Jersey Resources	6.9%	7.7%	7.8%	8.5%	6.3%	7.4%	6.5%	6.0%	5.0%	5.8%
NICOR	6.5%	1.5%	2.1%	2.3%	5.2%	3.5%	4.5%	5.0%	4.0%	4.5%
Northwest Natural Gas	1.9%	2.6%	2.7%	3.7%	4.2%	3.0%	5.0%	5.0%	4.5%	4.8%
Piedmont Natural Gas	1.7%	3.1%	3.7%	3.6%	2.8%	3.0%	3.5%	3.5%	3.5%	3.5%
South Jersey Industries	4.7%	5.0%	5.9%	6.2%	10.2%	6.4%	6.0%	6.5%	10.0%	7.5%
Southwest Gas	1.9%	1.7%	4.3%	2.2%	5.3%	3.1%	5.5%	6.5%	7.0%	6.3%
UGI	9.7%	9.2%	7.3%	11.5%	9.4%	9.4%	8.8%	9.0%	8.5%	8.8%
WGL Holdings	0.0%	6.2%	4.1%	4.6%	3.1%	3.6%	3.6%	4.0%	3.0%	3.5%
Average						5.3%				6.1%
Hanley Proxy Companies										
AGL Resources	7.0%	6.6%	5.6%	6.2%	6.3%	6.3%	5.0%	6.0%	6.0%	5.7%
Atmos Energy	1.9%	2.8%	1.7%	2.3%	3.6%	2.5%	3.0%	3.0%	4.0%	3.3%
Laclede Group	0.0%	3.1%	2.7%	3.1%	5.1%	2.8%	4.0%	3.5%	4.0%	3.8%
NICOR	6.5%	1.5%	2.1%	2.3%	5.2%	3.5%	4.5%	5.0%	4.0%	4.5%
Northwest Natural Gas	1.9%	2.6%	2.7%	3.7%	4.2%	3.0%	5.0%	5.0%	4.5%	4.8%
Piedmont Natural Gas	1.7%	3.1%	3.7%	3.6%	2.8%	3.0%	3.5%	3.5%	3.5%	3.5%
South Jersey Industries	4.7%	5.0%	5.9%	6.2%	10.2%	6.4%	6.0%	6.5%	10.0%	7.5%
WGL Holdings	0.0%	6.2%	4.1%	4.6%	3.1%	3.6%	3.6%	4.0%	3.0%	3.5%
Average						3.9%				4.6%

Source: Value Line Investment Survey.

COMPARISON COMPANIES PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '04-'06 to '10-'12 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Value Line Natural Gas								
AGL Resources	15.0%	4.0%	10.5%	9.8%	3.5%	5.5%	2.5%	3.8%
Atmos Energy	10.0%	2.0%	8.5%	6.8%	5.0%	1.5%	5.5%	4.0%
Energen	22.0%	4.0%	14.0%	13.3%	5.5%	7.0%	9.0%	7.2%
Laclede Group	6.5%	0.5%	3.5%	3.5%	4.0%	2.5%	5.0%	3.8%
New Jersey Resources	8.0%	3.5%	8.5%	6.7%	4.0%	5.0%	10.5%	6.5%
NICOR	-3.0%	2.5%	2.5%	0.7%	3.0%	0.0%	6.0%	3.0%
Northwest Natural Gas	3.0%	1.5%	3.5%	2.7%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas	5.0%	5.0%	6.5%	5.5%	4.0%	4.5%	2.5%	3.7%
South Jersey Industries	9.5%	3.5%	13.5%	8.8%		5.5%	4.5%	5.0%
Southwest Gas	6.0%	0.0%	3.5%	3.2%	8.0%	1.5%	4.0%	4.5%
UGI	22.5%	5.0%	25.0%	17.5%	7.0%	2.5%	11.5%	7.0%
WGL Holdings	6.0%	1.5%	3.0%	3.5%	2.0%	2.5%	4.5%	3.0%
Average	9.2%	2.8%	8.5%	6.8%	4.8%	3.6%	5.8%	4.7%
Hanley Proxy Companies								
AGL Resources	15.0%	4.0%	10.5%	9.8%	3.5%	5.5%	2.5%	3.8%
Atmos Energy	10.0%	2.0%	8.5%	6.8%	5.0%	1.5%	5.5%	4.0%
Laclede Group	6.5%	0.5%	3.5%	3.5%	4.0%	2.5%	5.0%	3.8%
NICOR	-3.0%	2.5%	2.5%	0.7%	3.0%	0.0%	6.0%	3.0%
Northwest Natural Gas	3.0%	1.5%	3.5%	2.7%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas	5.0%	5.0%	6.5%	5.5%	4.0%	4.5%	2.5%	3.7%
South Jersey Industries	9.5%	3.5%	13.5%	8.8%		5.5%	4.5%	5.0%
WGL Holdings	6.0%	1.5%	3.0%	3.5%	2.0%	2.5%	4.5%	3.0%
Average	6.5%	2.6%	6.4%	5.2%	4.1%	3.4%	4.3%	4.0%

Source: Value Line Investment Survey.

**COMPARISON COMPANIES
DCF COST RATES**

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Value Line Natural Gas								
AGL Resources	4.5%	6.3%	5.7%	9.8%	3.8%	5.0%	6.1%	10.7%
Atmos Energy	4.8%	2.5%	3.3%	6.8%	4.0%	5.3%	4.4%	9.2%
Energen	0.8%	12.9%	16.0%	13.3%	7.2%	7.2%	11.3%	12.1%
Laclede Group	4.5%	2.8%	3.8%	3.5%	3.8%	3.5%	3.5%	8.0%
New Jersey Resources	3.4%	7.4%	5.8%	6.7%	6.5%	5.1%	6.3%	9.8%
NICOR	4.6%	3.5%	4.5%	0.7%	3.0%	3.7%	3.1%	7.6%
Northwest Natural Gas	3.2%	3.0%	4.8%	2.7%	5.3%	4.9%	4.2%	7.4%
Piedmont Natural Gas	3.9%	3.0%	3.5%	5.5%	3.7%	5.2%	4.2%	8.1%
South Jersey Industries	3.1%	6.4%	7.5%	8.8%	5.0%	6.6%	6.9%	10.0%
Southwest Gas	3.1%	3.1%	6.3%	3.2%	4.5%	4.7%	4.4%	7.4%
UGI	3.0%	9.4%	8.8%	17.5%	7.0%	8.0%	10.1%	13.1%
WGL Holdings	4.2%	3.6%	3.5%	3.5%	3.0%	4.0%	3.5%	7.8%
Mean	3.6%	5.3%	6.1%	6.8%	4.7%	5.3%	5.7%	9.3%
Median	3.7%	3.6%	5.3%	6.1%	4.3%	5.1%	4.4%	8.7%
Mean Composite		8.9%	9.7%	10.4%	8.3%	8.9%	9.3%	
Median Composite		7.2%	8.9%	9.8%	7.9%	8.7%	8.1%	
Hanley Proxy Companies								
AGL Resources	4.5%	6.3%	5.7%	9.8%	3.8%	5.0%	6.1%	10.7%
Atmos Energy	4.8%	2.5%	3.3%	6.8%	4.0%	5.3%	4.4%	9.2%
Laclede Group	4.5%	2.8%	3.8%	3.5%	3.8%	3.5%	3.5%	8.0%
NICOR	4.6%	3.5%	4.5%	0.7%	3.0%	3.7%	3.1%	7.6%
Northwest Natural Gas	3.2%	3.0%	4.8%	2.7%	5.3%	4.9%	4.2%	7.4%
Piedmont Natural Gas	3.9%	3.0%	3.5%	5.5%	3.7%	5.2%	4.2%	8.1%
South Jersey Industries	3.1%	6.4%	7.5%	8.8%	5.0%	6.6%	6.9%	10.0%
WGL Holdings	4.2%	3.6%	3.5%	3.5%	3.0%	4.0%	3.5%	7.8%
Mean	4.1%	3.9%	4.6%	5.2%	4.0%	4.8%	4.5%	8.6%
Median	4.4%	3.3%	4.2%	4.5%	3.8%	4.9%	4.2%	8.1%
Mean Composite		8.0%	8.7%	9.3%	8.1%	8.9%	8.6%	
Median Composite		7.6%	8.5%	8.9%	8.2%	9.3%	8.5%	

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE 20-YEAR U.S. TREASURY BOND YIELDS RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		\$79.07			
1978	\$12.33	\$85.35	15.00%	7.90%	7.10%
1979	\$14.86	\$94.27	16.55%	8.86%	7.69%
1980	\$14.82	\$102.48	15.06%	9.97%	5.09%
1981	\$15.36	\$109.43	14.50%	11.55%	2.95%
1982	\$12.64	\$112.46	11.39%	13.50%	-2.11%
1983	\$14.03	\$116.93	12.23%	10.38%	1.85%
1984	\$16.64	\$122.47	13.90%	11.74%	2.16%
1985	\$14.61	\$125.20	11.80%	11.25%	0.55%
1986	\$14.48	\$126.82	11.49%	8.98%	2.51%
1987	\$17.50	\$134.04	13.42%	7.92%	5.50%
1988	\$23.75	\$141.32	17.25%	8.97%	8.28%
1989	\$22.87	\$147.26	15.85%	8.81%	7.04%
1990	\$21.73	\$153.01	14.47%	8.19%	6.28%
1991	\$16.29	\$158.85	10.45%	8.22%	2.23%
1992	\$19.09	\$149.74	12.37%	7.29%	5.08%
1993	\$21.89	\$180.88	13.24%	7.17%	6.07%
1994	\$30.60	\$193.06	16.37%	6.59%	9.78%
1995	\$33.96	\$215.51	16.62%	7.60%	9.02%
1996	\$38.73	\$237.08	17.11%	6.18%	10.93%
1997	\$39.72	\$249.52	16.33%	6.64%	9.69%
1998	\$37.71	\$266.40	14.62%	5.83%	8.79%
1999	\$48.17	\$290.68	17.29%	5.57%	11.72%
2000	\$50.00	\$325.80	16.22%	6.50%	9.72%
2001	\$24.69	\$338.37	7.43%	5.53%	1.90%
2002	\$27.59	\$321.72	8.36%	5.59%	2.77%
2003	\$48.73	\$367.17	14.15%	4.80%	9.35%
2004	\$58.55	\$414.75	14.98%	5.02%	9.96%
2005	\$69.93	\$453.06	16.12%	4.69%	11.43%
2006	\$81.51	\$504.39	17.03%	4.68%	12.35%
Average					6.40%

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

COMPARISON COMPANIES CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Value Line Natural Gas				
AGL Resources	4.49%	0.85	5.90%	9.5%
Atmos Energy	4.49%	0.85	5.90%	9.5%
Energen	4.49%	0.90	5.90%	9.8%
Laclede Group	4.49%	0.95	5.90%	10.1%
New Jersey Resources	4.49%	0.85	5.90%	9.5%
NICOR	4.49%	1.00	5.90%	10.4%
Northwest Natural Gas	4.49%	0.90	5.90%	9.8%
Piedmont Natural Gas	4.49%	0.85	5.90%	9.5%
South Jersey Industries	4.49%	0.85	5.90%	9.5%
Southwest Gas	4.49%	0.90	5.90%	9.8%
UGI	4.49%	0.85	5.90%	9.5%
WGL Holdings	4.49%	0.85	5.90%	9.5%
Mean				9.7%
Median				9.5%
Hanley Proxy Companies				
AGL Resources	4.49%	0.85	5.90%	9.5%
Atmos Energy	4.49%	0.85	5.90%	9.5%
Laclede Group	4.49%	0.95	5.90%	10.1%
NICOR	4.49%	1.00	5.90%	10.4%
Northwest Natural Gas	4.49%	0.90	5.90%	9.8%
Piedmont Natural Gas	4.49%	0.85	5.90%	9.5%
South Jersey Industries	4.49%	0.85	5.90%	9.5%
WGL Holdings	4.49%	0.85	5.90%	9.5%
Mean				9.7%
Median				9.5%

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010-2012
Value Line Natural Gas																			
AGL Resources	11.8%	12.7%	11.0%	11.6%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	11.8%	14.2%	12.5%	13.5%
Alamos Energy	10.7%	12.6%	13.4%	13.9%	12.2%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	20.3%	22.2%	11.4%	12.8%	9.9%	8.5%
Enbridge	9.9%	13.4%	13.9%	13.9%	11.3%	12.3%	11.0%	11.3%	14.3%	15.6%	12.4%	17.2%	17.0%	11.1%	11.1%	12.8%	17.8%	11.0%	21.5%
New Jersey Resources	12.1%	11.9%	11.5%	11.3%	14.4%	12.3%	11.4%	11.3%	8.5%	10.6%	7.8%	15.9%	15.2%	11.2%	10.0%	13.1%	14.6%	13.0%	15.8%
NICOR	15.3%	13.0%	13.0%	10.0%	11.9%	12.3%	14.5%	14.6%	14.3%	15.2%	15.9%	12.4%	15.8%	11.1%	10.9%	16.2%	15.8%	14.3%	13.0%
Piedmont Natural Gas	6.0%	15.3%	15.7%	13.3%	14.0%	13.8%	17.0%	16.9%	14.7%	18.2%	17.3%	9.2%	13.0%	10.1%	10.9%	10.5%	14.3%	14.0%	12.0%
South Jersey Industries	14.1%	13.7%	12.2%	12.2%	11.4%	14.6%	13.6%	13.6%	15.1%	12.0%	10.8%	13.2%	13.2%	10.9%	17.2%	13.0%	14.6%	11.6%	11.5%
UGI	11.8%	13.8%	12.2%	12.2%	11.1%	13.8%	13.6%	13.6%	15.1%	12.0%	10.8%	13.2%	13.2%	10.9%	17.2%	13.0%	14.6%	11.6%	11.5%
WGL Holdings	5.1%	11.0%	8.5%	9.2%	11.1%	11.9%	10.1%	10.1%	12.5%	15.4%	14.0%	16.5%	19.5%	16.1%	11.3%	20.0%	9.5%	12.0%	12.0%
Average	9.1%	3.2%	7.5%	9.0%	4.9%	9.2%	7.5%	7.3%	6.7%	22.7%	25.9%	6.2%	8.8%	6.5%	9.7%	5.6%	7.6%	9.5%	10.0%
Composite	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	10.3%	11.3%	11.9%	11.9%	14.4%	11.9%	12.1%	10.8%	12.4%	11.3%	11.1%	11.0%	10.5%
Hanley Proxy Companies																			
AGL Resources	10.9%	11.3%	11.5%	10.6%	12.3%	12.6%	11.9%	11.3%	12.6%	13.6%	12.6%	13.5%	12.7%	13.0%	13.8%	11.9%	13.1%	12.2%	12.4%
Alamos Energy	11.8%	11.0%	11.6%	13.1%	12.7%	12.6%	11.9%	11.3%	12.6%	13.6%	12.6%	13.5%	12.7%	13.0%	13.8%	11.9%	13.1%	12.2%	12.4%
Enbridge	10.7%	12.7%	10.0%	12.2%	12.3%	12.6%	11.9%	11.3%	12.6%	13.6%	12.6%	13.5%	12.7%	13.0%	13.8%	11.9%	13.1%	12.2%	12.4%
Laclede Group	9.9%	13.4%	13.9%	13.9%	11.3%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	20.3%	22.2%	11.4%	12.8%	9.9%	8.5%
NICOR	12.1%	11.9%	11.5%	11.3%	14.4%	12.3%	11.4%	11.3%	8.5%	10.6%	7.8%	15.9%	15.2%	11.2%	10.0%	13.1%	14.6%	13.0%	15.8%
Piedmont Natural Gas	6.0%	15.3%	15.7%	13.3%	14.0%	13.8%	17.0%	16.9%	14.7%	18.2%	17.3%	9.2%	13.0%	10.1%	10.9%	10.5%	14.3%	14.0%	12.0%
South Jersey Industries	14.1%	13.7%	12.2%	12.2%	11.4%	14.6%	13.6%	13.6%	15.1%	12.0%	10.8%	13.2%	13.2%	10.9%	17.2%	13.0%	14.6%	11.6%	11.5%
WGL Holdings	11.8%	13.8%	12.2%	12.2%	11.1%	13.8%	13.6%	13.6%	15.1%	12.0%	10.8%	13.2%	13.2%	10.9%	17.2%	13.0%	14.6%	11.6%	11.5%
Mean	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	10.3%	11.3%	11.9%	11.9%	14.4%	11.9%	12.1%	10.8%	12.4%	11.3%	11.1%	11.0%	10.5%
Composite	11.5%	12.9%	11.8%	12.2%	13.9%	13.3%	11.9%	11.1%	12.1%	12.9%	11.3%	11.8%	11.7%	12.8%	12.3%	12.0%	11.6%	11.7%	11.9%

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average
Value Line Natural Gas																	
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	179%	184%
Alamos Energy	158%	194%	186%	196%	248%	241%	245%	216%	167%	170%	150%	152%	147%	145%	146%	202%	148%
Energen	138%	171%	150%	145%	161%	186%	174%	147%	189%	215%	160%	194%	242%	308%	280%	168%	237%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	184%	184%	166%	171%
New Jersey Resources	181%	185%	162%	179%	180%	229%	225%	224%	227%	239%	220%	244%	251%	275%	247%	201%	247%
NICOR	179%	216%	195%	187%	190%	242%	269%	226%	227%	239%	169%	185%	210%	222%	234%	219%	210%
Northwest Natural Gas	162%	176%	161%	146%	158%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	135%	168%
Piedmont Natural Gas	180%	214%	186%	182%	163%	217%	222%	213%	193%	198%	186%	211%	212%	208%	221%	199%	208%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	195%	205%	185%	170%	195%	221%	209%	175%	198%
Southwest Gas	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	135%	161%	117%	133%
UGI	187%	162%	161%	166%	196%	226%	222%	186%	244%	292%	318%	286%	240%	279%	247%	205%	274%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	180%	168%
Average	159%	180%	163%	162%	180%	198%	202%	185%	182%	193%	180%	185%	193%	210%	205%	180%	195%
Composite																180%	192%
Hanley Proxy Companies																	
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	179%	184%
Alamos Energy	158%	194%	186%	196%	248%	241%	245%	216%	167%	170%	150%	152%	147%	145%	146%	202%	148%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	175%	184%	166%	171%
NICOR	179%	216%	195%	187%	190%	242%	260%	226%	227%	239%	195%	185%	210%	222%	234%	219%	210%
Northwest Natural Gas	162%	176%	161%	146%	158%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	155%	158%
Piedmont Natural Gas	180%	214%	186%	182%	163%	217%	222%	213%	195%	198%	186%	211%	212%	208%	221%	198%	208%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	175%	198%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	180%	168%
Mean	168%	193%	173%	169%	186%	201%	208%	186%	175%	183%	167%	173%	182%	190%	191%	184%	180%
Composite																184%	179%

Source: Calculations made from data contained in Value Line Investment Survey.

**STANDARD & POOR'S 500 COMPOSITE
RETURNS AND MARKET-TO-BOOK RATIOS
1992 - 2006**

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
Averages:		
1992-2001	14.7%	341%
2002-2006	14.1%	284%

Source: Standard & Poor's Analyst's Handbook, 2007 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Value Line Natural Gas	1.9	0.88	B++	B+
Hanley Proxy Companies	1.9	0.89	B++	B+
Southwest Gas	3.0	0.90	B	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

**SOUTHWEST GAS CORP.
PRE-TAX COVERAGE**

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Short-Term Debt	0.00%		0.00%	0.00%	
Long-Term Debt	52.08%	7.96%	4.15%	4.15%	
Preferred Stock	4.48%	8.20%	0.37%	0.61%	
Common Equity	43.44%	10.00%	4.34%	7.24%	
Total	100.00%		8.86%	12.00%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = $12.00\% / 4.15\%$
2.89

Standard & Poor[s Utility Benchmark Ratios:
Business Profile of "3"

A

BBB

Pre-tax coverage $2.8x - 3.4x$ $1.8x - 2.8x$

Total debt to total capital $50\%-55\%$ $55\%-65\%$

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON

Chairman

WILLIAM A. MUNDELL

Commissioner

JEFF HATCH-MILLER

Commissioner

KRISTIN K. MAYES

Commissioner

GARY PIERCE

Commissioner

IN THE MATTER OF THE APPLICATION OF)
SOUTHWEST GAS CORPORATION FOR THE)
ESTABLISHMENT OF JUST AND)
REASONABLE RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF SOUTHWEST GAS)
CORPORATION DEVOTED TO ITS)
OPERATIONS THROUGHOUT ARIZONA.)

DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

PHILLIP S. TEUMIM

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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**EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-04**

This testimony reviews the issues associated with line extension and hookup fees, and the Company's Research and Development ("R&D") and Demand Side Management ("DSM") programs and expenditures.

Line Extension and Hookup Fees: The Company is not proposing to change its tariffed line extension fees or implement a hookup fee. The testimony recommends that the company examine its construction, engineering and other processes associated with customer growth to determine whether and to what extent costs associated with those processes may be reduced. Consideration of hookup fees should be deferred to the concurrently running hookup fee docket. In the next rate proceeding, the Company should be required to demonstrate that its line extension fee is being implemented properly.

R&D: The Company has not proposed any changes to its R&D program in this proceeding. R&D programs and expenditures appear reasonable to date. However, it is too early to evaluate most of the programs, which are still in the early phases. Consideration should be given to allowing for increased total R&D funding, subject to the per therm cap on the R&D surcharge mechanism (Gas Research Fund rate) established in the previous rate case. The company should consider R&D projects directed toward reducing the cost of new construction.

DSM: the Company has not proposed any changes to its DSM programs in this proceeding. The majority of the DSM programs were implemented subsequent to the last rate case; data is not yet available to evaluate them. The Company should track and report additional information about its DSM programs, including "hard dollar" cost-benefit analyses and payback periods.

1 **INTRODUCTION**

2 **Q. Please state your name and business affiliation.**

3 A. My name is Phillip S. Teumim. I am a principal in the firm Phillip S. Teumim LLC, 37
4 Ruxton Road, Delmar NY 12054, a management and regulatory consulting firm providing
5 consulting services on utility matters. I am appearing on behalf of the Arizona
6 Corporation Commission ("ACC", or "Commission") Utilities Division ("Staff").
7

8 **Q. Please describe your education and professional experience.**

9 A. I hold a Bachelor of Science degree in Electrical Engineering and a Master's degree in
10 Business Administration from Rensselaer Polytechnic Institute in Troy New York. I was
11 employed by the New York State Public Service Commission ("PSC") from 1970 to 1988,
12 and again from 1992 to 2002. During the period 1988 to 1992, I worked for the consulting
13 firm of Theodore Barry & Associates, and later Resource Management International.
14 During my tenure with the PSC, I worked extensively on telecommunications, electric,
15 gas, and water matters. During my second stint with the PSC, I was the Director of the
16 Energy and Water Division, and later the Gas and Water Division. In 2002 I started my
17 own consulting firm, and have worked on gas, electric and water matters for a variety of
18 clients in various jurisdictions since that time. My resume is included as Exhibit No. PST
19 - 1.
20

21 **Q. What is the purpose of your testimony in this proceeding?**

22 A. I have examined and will comment on the issues associated with line extension charges
23 and hookup fees, I have also reviewed Southwest Gas Corporation's ("Southwest Gas" or
24 "Company") Research and Development ("R&D") and Demand Side Management
25 ("DSM") programs and offer comment on those programs as well.
26

LINE EXTENSION AND HOOKUP FEES

Q. Please explain those terms as you use them.

A. At the outset, I want to point out that in my experience there is no universally applicable definitions of a line extension fee and hookup fee. I will discuss the two terms conceptually below, noting that in practical applications, the boundaries are often muddled or ignored.

Q. What is the purpose of a line extension fee?

A. Line extension fees are intended to compensate utilities for the costs of extending mains and service lines to customers, generally above a certain "free footage" allowance. Such fees also provide for equity among new customers, in that there are usually significant cost differences to connect a customer very close to the main as compared to a customer located some distance from it. Under the "free footage" approach, both customers are entitled to a certain length of main and service line at no charge, and beyond that are charged either actual or average per foot cost.

Q. What is the purpose of a hookup fee?

A. A hookup fee is intended to compensate the utility for all other costs of connecting a new customer, other than the specific main and service line costs, where the incremental cost of the new customer exceeds the embedded cost of existing customers. Such costs may include, for example, expenditures to reinforce the company's backbone supply system, acquiring additional peaking facilities, additional warehouse space and workout locations, etc.

Q. Please explain the underlying issues associated with line extension and hookup fees.

A. The issues arise out of the relationship between the embedded cost of existing facilities

1 and the incremental costs associated with servicing a new customer. There are a number
2 of factors that go into the cost equation for providing utility service, including cost of
3 capital, cost of labor, cost of materials, mix of residential and non-residential customers,
4 density of structures being served, proportion of those new structures taking utility
5 service, and other factors.

6
7 For most established utilities, once they were past the startup phase, the economics were
8 such that the addition of new customers tended to spread their fixed costs over a larger
9 base, yielding economies of scale and tending to drive down the average cost (and
10 therefore rates) per customer. As a way of encouraging customers to hook up, and to
11 provide some level of equity among existing and new customers, utilities developed "free
12 footage" allowances. Those allowances took various forms, such as:

- 13
- 14 • A specified number of feet of main or line extension,
 - 15 • A specified number of feet of service line or pipe,
 - 16 • A combined length of the two,
 - 17 • A specified dollar allowance, computed by a formula which takes into account a
18 standard footage multiplied by the average cost of the prior year's installations.
- 19

20 The allowance is typically determined by service classification or size of pipe.

21

22 Historically, some utilities even paid customers, particularly those with alternate supplies
23 (e.g., self-generators, on the electric side) to shut down their facilities and hook up to the
24 utility.

25

1 **Q. Are those costs regularly updated?**

2 A. In my experience, where lengths of "free footage" are specified, they are rarely updated.
3 Proceedings to examine those allowances generically are few and far between and may go
4 on for years, in part because they have no statutory deadlines. To the extent that utilities
5 employ a formula based on recent costs, such as is the case here, those numbers are
6 typically updated annually. Occasionally, those issues are addressed in rate cases.
7

8 **Q. What factors should be considered in determining whether to implement or change**
9 **line extension and hookup fees?**

10 A. Factors include:

- 11
- 12 • Cost disparity between incremental and embedded mains and service lines,
 - 13 • Cost disparity between all other embedded and incremental costs,
 - 14 • The relationship between the two,
 - 15 • Existing fees and policies,
 - 16 • The extent to which disruption will occur as a result of changing policies or costs, and
 - 17 • Actual costs of new hookups.
- 18

19 **Q. Please discuss the actual costs of new hookups.**

20 A. In my opinion, this is the most neglected part of the analysis and discussion. As a general
21 rule, utilities focus primarily on recovering the costs and direct far less attention to
22 controlling and reducing the costs. Utilities are often unaware of the specific cost
23 components, the cost drivers, and have not looked to understand and to drive down the
24 costs of new hookups. Utilities often do not compare their costs with others and look for
25 best practices to reduce their costs.

1 Further, in my experience, there is a wide range of cost elements which utilities include,
2 appropriately or inappropriately, in calculating line extension fees. Typically, tariffs
3 contain only a general description of the costs allowed, and the actual calculations are left
4 to the utilities.

5
6 **Q. Does the shortcomings identified in the previous response apply to Southwest Gas?**

7 A. Southwest Gas appears to have fairly good cost data for installation of the various sizes of
8 mains and services. (Exhibit No. PST-2) However, the Company does not appear to have
9 examined the cost side of the equation. A review of the Company's recent internal audits
10 (Exhibit No. PST-3), the lack of outside management or process reviews (Exhibit No.
11 PST-4), and the absence of identified cost savings programs in the new construction area
12 (Exhibit Nos. PST-5 and PST-6) indicates a relative lack of attention to the construction-
13 related processes and costs.

14
15 **Q. Can you cite any examples in which other utilities have investigated such costs and**
16 **processes?**

17 A. Yes. I have personal experience with a mid-sized East coast utility that was experiencing
18 very high growth, with consequent upward pressure on rates. The utility had compared
19 itself to several other high growth utilities and determined that its cost per new hookup
20 was several times higher than the others it surveyed. A further analysis demonstrated that
21 there were a number of processes and techniques in use by the other utilities that
22 significantly reduced their costs.

23
24 In particular, the utility observed that its engineering, construction and customer services
25 process were highly inefficient, and significant economies could be achieved.
26

1 I will cite from the Executive Summary of a management audit of that utility:

2
3 *It is in the area of expansion and growth that the company faces its*
4 *greatest challenges. The company is pursuing an aggressive expansion*
5 *program in its existing service territory as well as actively seeking*
6 *additional franchise areas. All other things being equal, we believe*
7 *residents of Maryland (and other jurisdictions served by the company as*
8 *well) are better off having gas service available to them. It fosters*
9 *competition, is one of, if not the most environmentally preferable fuels, and*
10 *is domestically produced.*

11
12 *The catch is "all other things being equal." We believe that in order to*
13 *support its aggressive expansion program, the company must be equally*
14 *aggressive in reducing the costs of new construction and their associated*
15 *effects on rates. At this time, most of the company's efforts in this area are*
16 *directed toward growth with a much lower level of effort toward reducing*
17 *costs of new construction. We believe that the effort needs to be balanced*
18 *until costs have been significantly reduced. Costs per new hookup are*
19 *running over three times greater than average embedded cost per*
20 *customer. The company must ask and answer the question "How close to*
21 *embedded cost can we bring incremental costs?"*¹

22
23 I have included excerpts from that audit dealing with this issue in Exhibit No. PST-7. I
24 find the excerpts I have included from that audit to be equally relevant to Southwest Gas.

25
26 **Q. What do you recommend in this instance?**

27 **A.** I recommend that the Commission direct Southwest Gas to do the following:

- 28
29 • Compare its new construction and hookup costs to other utilities both within and
30 outside Arizona.
31
32 • Perform a "best practices" review of engineering, construction, and business
33 processes.

¹ Management Audit of the Maryland Natural Gas Division of the Washington Gas light Company, Theodore Barry & Associates, April 1990, p. II-2

- Examine and consider re-engineering processes, procedures and methods associated with building out to and connecting new customers.

Q. How do your recommendations comport with the “hookup fee” proceedings, Docket Nos. E-00000K-07-0052 and G-00000E-07-0052?

A. I am not making any specific recommendations as to whether hookup fees should be implemented. The cited hookup fee proceeding is the appropriate docket for that determination. I do recommend that Southwest Gas not implement any such fee until it performs the studies and analysis I recommend in my testimony.

Q. How does Southwest Gas calculate line and service extension fees?

A. The Company’s tariff, Rule Number 6, provides that allowable investment in line extensions and services is determined using an Incremental Contribution Study, and that the applicant must provide a return equal to the Company’s allowed rate of return; the customer is charged for any additional amounts, subject to later refund under certain conditions.

Q. What is your opinion of this methodology?

A. Conceptually, this is a reasonable methodology. Assuming it is properly applied, it has the advantage of using current cost figures and revenue estimates. I have not examined the application of the methodology, and cannot comment on that.

Q. Do you have any recommendations with respect to line and service extension fees?

A. Yes. The cost side of the equation is addressed by my recommendations concerning hookup fees, in that the costs of construction referred to in that discussion apply to both hookup fees and main and service line extensions. It does appear that the Incremental

1 Contribution Study methodology and application has not been examined in some time, and
2 that particular tariff section was last updated some 10 years ago. I recommend that, in the
3 next rate proceeding, the Company file an explanation, with sample calculations, of how it
4 has been implementing those tariff provisions, and explain whether and to what extent it
5 has made changes in the methodology and its application over the 10 years the tariff has
6 been in place. The Hookup Fee proceedings may also generate useful new information in
7 this context.
8

9 **RESEARCH AND DEVELOPMENT ("R&D")**

10 **Q. What did the Commission conclude in the last rate proceeding with respect to R&D**
11 **funding?**

12 A. To replace the funding for the Gas Technology Institute, which had been previously
13 provided via a FERC surcharge that was no longer in effect, the Commission allowed
14 Southwest Gas to fund R&D programs at a level of \$688,712 per year, which was to be
15 recovered on a per therm basis from the Company's sales customers, excluding G-30
16 (Optional Gas Service) and B-1 customers. The Commission further allowed Southwest
17 Gas the discretion to fund projects undertaken by research organizations other than GTI,
18 as well as continuing to fund GTI projects, subject to Commission oversight. (Decision
19 No. 68487, Docket No. G-01551A-04-0876, pp 60 – 61)
20

21 **Q. How are the R&D funds collected from customers?**

22 A. The Southwest Gas tariff includes a Rate Adjustment charge of \$0.00074 per therm, for
23 the Gas Research Fund. (Southwest Gas Tariff – Arizona No. 7, sheet No. 13) This is a
24 balancing account which is used by the Company to fund the R&D program. The charge
25 is updated annually on May 1.
26

1 **Q. Has the level of surcharge been modified since first implemented?**

2 A. Yes. The surcharge was first implemented effective March 1, 2006, at a level of \$0.00113
3 per therm, and was reduced to its current level effective March 1, 2007.

4
5 **Q. How much was collected through the surcharge?**

6 A. From inception on March 1, 2006 through November 2007, Southwest Gas collected
7 \$1,074,582. (Exhibit No. PST-8)

8
9 **Q. Have you reviewed the Company's R&D expenditures?**

10 A. Yes. For the five-year period 2002 through 2006, Southwest Gas spent a total of \$95,000
11 directly on R&D projects. This is exclusive of projects it funded indirectly through the
12 FERC-imposed R&D pipeline surcharge. While I do not find those projects unreasonable,
13 the level of expenditures was very small compared to the current program. The balance of
14 this discussion on R&D is directed toward the new programs.

15
16 **Q. Have you reviewed the Company's process for selecting R&D projects to support?**

17 A. Yes, I reviewed the specific projects supported by the Company and its process for
18 selecting projects, as provided in response to various data requests. Southwest Gas is
19 funding projects in the following areas:

- 20
21 • Solar air conditioning with natural gas backup,
22 • Hot water heating using a natural gas driven heat pump,
23 • Gas interchangeability,
24 • Guided wave ultrasonic tools to assess pipe conditions,
25 • Assessing the resistance of polyethylene pipe to rock impingement,
26 • Long term evaluation of polyethylene pipe fusion joints,

- 1 • General evaluation of R&D budgets and projects in the industry,
- 2 • General evaluation of various technical issues, and
- 3 • Determining the yield strength of installed steel pipe.

4

5 **Q. What have you concluded about the Company's R&D program and funding?**

6 A. While it is still very early in the process, and expenditure data is not yet available for the

7 first full year of the program, I can offer some preliminary conclusions.

- 8
- 9 • Southwest Gas appears to employ a reasonable process and procedures in selecting
 - 10 projects for consideration and in evaluating those projects,
 - 11
 - 12 • The projects selected appear to be reasonable R&D projects for Southwest Gas to
 - 13 support,
 - 14
 - 15 • The joint funding approach toward projects of common interests provides substantial
 - 16 leverage to the Company's R&D expenditures, and
 - 17
 - 18 • When viewed as a percentage of revenues, the Company's expenditures are very low,
 - 19 under one-tenth of one per cent.
- 20

21 **Q. Do you have any recommendations for changes or improvements to the program?**

22 A. Yes. I would like to see a closer linkage between R&D projects undertaken and corporate

23 priorities and pressures. For example, one of the greatest challenges facing Southwest Gas

24 is the high growth environment and the upward pressure being exerted on rates, as

25 discussed earlier in this testimony. However, I see little or no emphasis placed on R&D

26 projects which might contribute to easing those pressures. I would point out that in the

1 last rate case, Southwest Gas asked for, and the Commission approved, giving the
2 Company flexibility to "...tailor the research funds to the projects and organizations best
3 suited for a specific need...." (Decision No. 68487, Docket No. G-01551A-04-0876, p.
4 60) I believe a specific need is clearly demonstrated by the upward pressures on rates
5 driven by new construction.
6

7 **Q. Can you give some examples of the types of projects you are encouraging?**

8 A. Such projects might include new main and service line installation technologies and
9 development of equipment to more quickly and accurately locate underground facilities.
10

11 **Q. How is R&D currently funded?**

12 A. The current R&D funding mechanism, established in the last rate case, specified a specific
13 annual R&D funding level of \$688,712, which is collected through the Gas Research Fund
14 ("GRF") rate, and applied on a per therm basis to most sales customers. The actual per
15 therm charge is determined by dividing the allowed funding level by the most recent 12
16 months' applicable sales volumes, and is updated annually effective May 1. The charge is
17 currently \$0.00072 per therm.
18

19 **Q. Do you have any recommendations with respect to R&D funding?**

20 A. Yes. The level of R&D expenditures is very low when viewed as a percent of revenues,
21 and may not provide sufficient funding for worthy projects, particularly if the Company is
22 to pursue projects as recommended in this testimony. The per therm charge decreased
23 from \$0.00113 to \$0.00072 in the first two years of the current program, and can be
24 expected to continue to decrease as the Company grows and sales increase. Since the
25 Commission found the first year level reasonable, it could freeze the GRF rate at that
26 level. If that were the case, the total R&D funds that would be available would be equal to

1 the \$0.001113 rate multiplied by the number of therms sold in the prior year. Under that
2 approach, as sales grow the available R&D funding would grow, but the per therm charge
3 would not increase.

4
5 **Q. Do you recommend the Commission do so at this time?**

6 A. No. However, I do recommend that the Commission allow for an increase up to that level
7 discussed above subject to the Company proposing worthy new projects and the ongoing
8 process of Staff review and Commission oversight.

9
10 **DEMAND SIDE MANAGEMENT ("DSM")**

11 **Q. Have you reviewed the Southwest Gas DSM program?**

12 A. Yes. I reviewed the Commission's Decision No. 68487 in the company's last rate
13 proceeding (Docket No. G-01551A-04-0876), the company's semiannual DSM reports for
14 the last 5 years, and the responses to DSM-related interrogatories STF-5-1 through STF-5-
15 5.

16
17 **Q. Do you have any comments on the individual programs?**

18 A. At the outset, I want to point out the DSM programs developed as a result of the last rate
19 case and the subsequent collaborative are still in the early stages, and actual data are not
20 yet available. The company indicates that ... *a portion of the Southwest portfolio was in*
21 *transitional stages or began in late 2007...*, that most of the programs will be fully
22 implemented in 2008, and that it intends to evaluate all the DSM programs at the
23 conclusion of the 2008 program year. (Exhibit No. PST-9, pp. 1-2) I would point out that
24 the previous statement in fact applies to most of the DSM programs and dollars, as the
25 budgets for 2006, 2007 and 2008 program years are \$750,000, \$955,500, and \$3,060,000,

1 respectively. (Exhibit No. PST-9, Table 2) Therefore, I believe it would be premature to
2 attempt to evaluate the relative success of the programs.

3
4 However, I do have some observations on the data collected and reported by Southwest
5 Gas. The Company does not calculate a payback period for any of the DSM programs,
6 and evaluates the programs using a cost-benefit ratio based on total resource costs and
7 estimated lifetime energy savings. (Exhibit No. PST-9, Table 1) The Company stated that
8 it does not calculate a payback period because ...*Neither ACC Staff nor the Commission*
9 *has requested or required this information in any past DSM filings.* (Exhibit No. PST-9, p.
10 2) I recommend that the Company track and report estimated and actual hard dollar cost-
11 benefit analyses and payback periods.

12
13 **Q. Please explain what you mean by a hard dollar cost-benefit analysis.**

14 A. Energy efficiency programs yield savings in the form of direct dollar benefits, such as
15 lower energy consumption and lower energy bills, as well as indirect savings, such as
16 improved air quality and more efficient use of resources. The total resource cost-benefit
17 analysis which Southwest Gas has estimated includes both direct and indirect costs and
18 direct and indirect benefits. By their nature, some of those softer, indirect costs and
19 benefits are difficult to measure and require a number of assumptions. Direct costs and
20 benefits are much more straightforward and measurable. In my view, it would be
21 beneficial to capture and review both sets of data. The total resource cost result gives no
22 indication of the relative contribution of hard and soft costs to that final result.

23
24 **Q. Would you apply those requirements to the existing as well as the new programs?**

25 A. No. The two existing, longer running programs are the Energy Advantage Plus Program,
26 designed to upgrade the energy efficiency of new housing stock, and the Low Income

1 Energy Conservation Program, designed to provide home weatherization as well as
2 emergency bill assistance. The former program is designed to provide benefits for the life
3 of the structure, and the latter has a significant low-income assistance component, and the
4 emergency assistance component is technically not a DSM measure. Both of those
5 programs have extenuating circumstances which, in my view, should exempt them from
6 the requirements. In contrast, the new programs are targeted energy efficiency programs,
7 for activities such as purchase of more efficient appliances and commercial equipment,
8 providing of commercial food service, and distributed generation. Those programs tend to
9 produce more hard dollar savings and lend themselves to more direct quantification.

10
11 **Q. Does that conclude your Direct Testimony?**

12 **A. Yes, it does.**

Resume

Phillip S. Teumim

Mr. Teumim has 35 years of experience as a regulator and consultant in the utility industry, including a substantial period of time focused on natural gas industry. He has experience in all facets of the natural gas business, from senior level policy issues to technical matters, including regulatory and competitive policy development and implementation, rate proceedings and ratemaking, LDC gas costs, LDC supply and capacity portfolios, and development and enforcement of gas safety requirements for pipelines and LDCs.

From 1992 to 2002, Mr. Teumim was Director of the Office of Gas & Water and its predecessor office for the New York State Public Service Commission. As such he was a senior policy and technical advisor to the Commission on all natural gas and water matters, and technical and administrative director of an office of some 70 engineers and analysts, with an annual budget of approximately \$5 million. His responsibilities included regulatory and competitive policy development and implementation, rate proceedings and ratemaking, review of LDC strategic and corporate planning, annual reviews of LDC gas costs, annual reviews of LDC supply and capacity portfolios, review of affiliate relationships and transactions, intervention in FERC natural gas proceedings, and enforcement of gas safety requirements for LDCs and, as agents for federal DOT, for interstate pipelines and facilities.

Earlier, he worked as a management consultant in the areas of corporate governance, planning, organization, rates and regulatory affairs, and as a regulatory engineer and analyst in the areas of rates and valuation, management auditing, nuclear prudence auditing, and customer service.

Mr. Teumim is a frequent speaker on natural gas, energy, water and regulatory matters before utility groups, industry organizations, trade associations, NARUC conferences and committees. He has testified on numerous occasions before state regulatory commissions, state legislative committees and the FERC, and has also been a guest instructor for NARUC and various trade and industry conferences.

Specific gas safety and related accomplishments and activities during his tenure as Director at the New York PSC include:

- Development of the annual performance measures report, which compared the performance of all New York LDCs on key safety indicators, including leak repair, emergency response, and damage prevention to underground facilities
- Institution of the program of heightened awareness of protection of underground facilities and assessment of penalties for damages to them

- Transition of the PSC's gas safety program from a technician-oriented field approach to an engineering-oriented preventive approach
- Institution of quarterly safety meetings with senior LDC gas safety personnel, and regular meetings with statewide organization of LDC safety personnel

Other activities and accomplishments include:

- Lead role in conducting a series of some 15 roundtables, with a broad spectrum of industry stakeholders in the Northeast, on development of competitive policies. Developed white paper, which was subsequently adopted by the Commission, laying out a vision and policy for the natural gas industry in New York.
- Lead negotiator in negotiating settlements of multi-year rate and competitive issues with several large LDCs; senior team advisor on all such negotiations and settlements with all New York LDCs.
- Developed and implemented, after Commission approval, a policy statement on gas purchasing practices and risk management, which lays out the general guidelines for LDCs' use of financial instruments ("hedging").
- Lead negotiator for the NY PSC in the restructuring of an electric utility, including divestiture of generation, development of a multi-year rate plan, and implementation of a customer choice program.
- Lead role in development and oversight of agency's positions as an intervener in FERC proceedings and rulemakings. Included appearances and testimony at various FERC technical conferences.
- Established and chaired New York's Natural Gas Reliability Advisory Group, a 24 member counsel, representing all stakeholder groups, which addresses pipeline supply issues.
- Project manager for a state commission-ordered study of the gas supply and integrated resource planning, and affiliate relationships for a large, vertically integrated LDC in the Southwest; lead consultant in the area of organization, strategic planning and affiliate relations and transactions. Included testimony before the state Commission.
- Project manager for a management audit of a Middle Atlantic LDC for a regulatory commission; lead consultant in the areas of corporate governance, strategic and corporate planning, and organization.
- Project manager for a management audit of a large northeastern public power authority for a state agency; lead consultant in the areas of corporate governance,

including the performance of the board of trustees, strategic planning, organization and ratemaking.

- Performed a detailed evaluation of the performance of the board of directors of a large northeastern utility during the 15-year construction of a nuclear plant, including a review of all board activities and all reports and other information provided to the board.
- Lead consultant in an audit of the governance and corporate structure of a multi-board generation and transmission cooperative, purchasing agent and trade organization owned by 27 electric cooperatives in a large eastern state. Performed diagnostics and restructured three separate boards of directors into a nine-member executive board and a plenary board.
- Lead consultant in the areas of gas supply management and operations for two commission-ordered audits of Midwestern utilities, including the evaluation of arrangements with affiliated asset managers.

Education:

MBA, BS (Electrical Engineering), Rensselaer Polytechnic Institute,
Troy NY

253-009

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

* * *

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-5
(ACC-STF-5-1 THROUGH ACC-STF-5-20)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 26, 2007

Request No. STF-5-9:

Please provide a schedule of the most recently available embedded cost per foot of main and service, by diameter, for all main extensions and services for which customers may be charged under the provisions of the Company's tariff.

Respondent: Revenue Requirements

Response:

The Company's line extension policies are set forth in Rule 6, Service and Main Extensions, of Southwest's Arizona Gas Tariff. Southwest follows an "Incremental Contribution Method" (ICM) to determine the allowable investment and advances and contributions, if any, required from applicants for service, or developers. Southwest uses the ICM to determine the economic feasibility for each project, based on the unique circumstances of each request and the latest available data for the costs to install mains and services. The purpose of the ICM is to ensure that when the incremental costs to provide service to new customers is compared to the expected incremental revenues, the new line extension will produce at least the Commission-authorized rate of return (ROR). If the expected revenues, compared to the costs of the particular extension, are less than the authorized ROR, then a contribution in aid of the construction is required. This ensures that the persons' responsible for imposing additional costs on the utility system pay for such additional costs.

The Company's line extension practice for "New Mains" is to use engineering cost estimates based on the specific characteristics of the project being reviewed. The Company's line extension practice for "New Services" relies on the use of standard average length (feet) and dollars per foot based on historical averages. The standard amounts are derived from statistics obtained from blanket work orders established to capture the construction costs related to residential, multi-family and

(Continued on Page 2)

Response to STF-5-9: (continued)

commercial customer rate classes. Southwest uses historical average cost per foot and standard lengths for service stubs (the portion of service extension from the main to three feet beyond either the curb or sidewalk). The service stub is installed simultaneously with the main. This enables the builder/developer to pave the streets and roads in a given development and helps avoid the delay and expense of having to subsequently cut the pavement to install the under pavement portion of the gas service facility (or any other utility facility). The Service extension is the portion of the service line that runs from the end of the stub to the customer meter. The average stub and service length used in line extension analyses for the years 2007 and 2008 (based on the three-year average for 2005 through 2007) is contained in the attached summary.

Although the costs to install new main extensions are based on specific estimates, Southwest maintains a statistical data base that derives the average cost per foot of main cost by certain sizes and types of pipe. This information is also available for services. Attached is a summary of the results for years 2002 through 2007 by operating district and summarized for Arizona.

SOUTHWEST GAS CORPORATION
ARIZONA

RESIDENTIAL SUBDIVISION SERVICE COST STANDARD AMOUNTS
COMPARE THREE-YEAR 2005-2007 HISTORICAL TO 2007 ICM

Description	District Operations					
	Valley	Bullhead	Tucson	Phoenix	Southeast	Yuma
	32	City 34	36	42	47	48
Service Line Extension 2007						
Service-Stub Avg. Ft.	20	20	20	15	20	20
Service-Extension Avg. Ft.	28	40	34	33	41	50
Average Residential Service Ft.	48	60	54	48	61	70
Average Cost Per Ft.	10.25 \$	13.00 \$	8.00 \$	9.00 \$	8.25 \$	12.00 \$
Average Cost Per Service	492 \$	780 \$	432 \$	432 \$	503 \$	840 \$
Services Line Extension 2008						
Three-Year History (2005-2007)						
Service-Stub Avg. Ft.	20	20	20	15	20	20
Service-Extension Avg. Ft.	30	31	40	22	44	33
Average Residential Service Ft.	50	51	60	37	64	53
Average Cost Per Ft.	8.62 \$	14.10 \$	8.55 \$	14.18 \$	9.38 \$	10.15 \$
Average Cost Per Service	431 \$	719 \$	513 \$	525 \$	600 \$	538 \$

The above are used for single family subdivision new service cost estimates
Random residential customers generally require additional service footage.

Note: The residential less than two inch service cost amounts on the subsequent sheets represents
the total of single family subdivision, random and a small amount of multi-family customer additions.

SOUTHWEST GAS CORPORATION
ARIZONA
NEW MAIN AND SERVICE FOOTAGE AND COST STATISTICS
FOR THE SIX YEAR PERIOD 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9

Description	Valley 32	BHC 34	Tucson 36	Phoenix 42	S. E. 47	Yuma 48	Arizona
Residential Customer	14,383	5,763	44,916	153,016	4,493	5,419	227,991
All First Time Meter Sets	14,677	5,821	46,305	156,384	4,831	6,543	234,561
Mains							
2" PE (\$ Per Ft.)	\$ 6.13	\$ 9.31	\$ 7.04	\$ 9.94	\$ 6.43	\$ 5.57	8.89
4" PE (\$ Per Ft.)	\$ 9.29	\$ 22.70	\$ 12.49	\$ 22.61	\$ 10.10	\$ 4.60	16.57
6" PE (\$ Per Ft.)	\$ 0.00	\$ 25.99	\$ 18.50	\$ 22.00	\$ 0.00	\$ 0.00	21.88
2" PE (Ft. Per Res Cust)	69	40	50	55	65	75	55
4" PE (Ft. Per Cust)	16	9	9	10	15	68	12
6" PE (Ft. Per Cust)	0	1	1	4	0	0	3
2" PE (\$ Per Res Cust)	\$ 420	\$ 373	\$ 352	\$ 547	\$ 417	\$ 420	491
4" PE (\$ Per All Cust)	\$ 153	\$ 205	\$ 114	\$ 215	\$ 155	\$ 314	193
6" PE (\$ Per All Cust)	\$ 0	\$ 37	\$ 12	\$ 79	\$ 0	\$ 0	56
Services							
<2" PE (\$ Per Ft.)	\$ 9.3	\$ 12.2	\$ 8.7	\$ 11.4	\$ 8.0	\$ 11.4	10.5
2" PE > PE (\$ Per Ft.)	\$ 12.7	\$ 12.2	\$ 23.3	\$ 29.0	\$ 13.4	\$ 15.3	27.6
<2" PE (Ft. Per Res. Cust.)	48.5	59.9	68.9	44.0	84.1	67.6	51.0
2" PE or > (Ft. Per Non-Res.)	1.1	0.8	2.2	4.5	2.0	1.0	3.6
<2" PE (\$ Per Res. Cust.)	\$ 449	\$ 731	\$ 601	\$ 503	\$ 675	\$ 771	535
2" PE > PE (\$ Per Non-Res)	\$ 14	\$ 9	\$ 52	\$ 132	\$ 26	\$ 16	100
g. \$ Per Res. Cust. 2" Main	\$ 420	\$ 373	\$ 352	\$ 547	\$ 417	\$ 420	491
Avg. \$ Per Res. Cust. <2" Service	\$ 449	\$ 731	\$ 601	\$ 503	\$ 675	\$ 771	535
Avg. \$ Per Res. Cust. 4"/6" PE Main	\$ 153	\$ 243	\$ 126	\$ 295	\$ 155	\$ 314	249
Avg. \$ Per Res. Cust. Steel Main	\$ 97	\$ 0	\$ 2	\$ 104	\$ 17	\$ 5	76
Mains							
2" PE (Ft.)	986,478	231,076	2,247,208	8,423,603	291,334	408,652	12,588,351
4" PE (Ft.)	241,243	52,649	422,518	1,489,475	74,077	446,825	2,726,787
6" PE (Ft.)	0	8,349	30,073	563,755	0	0	602,177
Steel (Ft.)	38,807	0	15,329	183,432	43,897	616	282,081
2" PE (\$)	\$ 6,043,935	\$ 2,151,385	\$ 15,824,598	\$ 83,717,107	\$ 1,873,891	\$ 2,277,630	\$ 111,888,546
4" PE (\$)	\$ 2,240,530	\$ 1,195,139	\$ 5,275,196	\$ 33,669,609	\$ 748,307	\$ 2,057,086	\$ 45,185,866
6" PE (\$)	\$ 0	\$ 216,973	\$ 556,466	\$ 12,401,491	\$ 0	\$ 0	\$ 13,174,931
Steel (\$)	\$ 1,422,769	\$ 0	\$ 103,786	\$ 16,255,709	\$ 83,108	\$ 34,520	\$ 17,899,893
Services							
<2" PE (Ft.)	697,011	345,037	3,095,833	6,737,737	377,854	366,348	11,619,820
2" PE > PE (Ft.)	16,103	4,344	103,703	709,922	9,353	6,700	850,125
<2" PE (\$)	\$ 6,459,969	\$ 4,211,340	\$ 26,976,980	\$ 77,026,526	\$ 3,032,410	\$ 4,178,430	\$ 121,885,656
2" PE > PE (\$)	\$ 204,114	\$ 52,843	\$ 2,418,754	\$ 20,575,890	\$ 124,905	\$ 102,329	\$ 23,478,836

**SOUTHWEST GAS CORPORATION
ARIZONA
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEAR 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9**

Description	Valley	Bullhead City	Tucson	Phoenix	Southeast	Yuma
New Meter Sets	2,904	608	5,945	20,446	622	568
Residential @ 97% of Total	2,846	602	5,767	20,037	578	545
Non-Residential @ 3% of Total	58	6	178	409	44	23
Mains (BI 9603)						
2" or Less PE Feet (Unitized)	58,376	18,400	220,646	883,042	20,869	36,993
2" or Less PE Dollars (Unitized)	\$ 23,724	\$ 343,196	\$ 1,632,137	\$ 10,364,664	\$ 170,352	\$ 171,899
Dollars Per Ft	\$ 0	\$ 19	\$ 7	\$ 11.74	\$ 8.16	\$ 4.65
4" PE Unitized	17,280	7,331	51,973	91,623	20,447	17,128
6" PE Unitized	0	0	6,028	29,732	0	0
4" & 6" PE Dollars Unitized	\$ 206,444	\$ 369,753	\$ 943,349	\$ 3,274,354	\$ 203,967	\$ 189,479
4" & 6" PE Dollars Per Ft	\$ 12	\$ 50	\$ 16	\$ 842,191.00	\$ 9.98	\$ 11.06
Steel Ft.	94	0	6	7,663	0	0
Steel Dollar	\$ 1,528	\$ 0	\$ 452	\$ 1,874,486	\$ 0	\$ 0
Steel Dollars Per Ft.	\$ 1,528	\$ 0	\$ 203	\$ 245	\$ 0	\$ 0
Total Main Footage (Unitized)	75,750	25,731	278,657	1,012,070	41,316	54,121
Total Main Dollars (Unitized)	\$ 231,696	\$ 712,957	\$ 2,580,951	\$ 16,394,544	\$ 374,319	\$ 361,480
Total (Unitized) Mains Dollars Per Ft	\$ 3	\$ 28	\$ 9	\$ 16.20	\$ 9.06	\$ 6.68
Total Charges to BI 9603 (Incl. O/H)	\$ 1,835,250	\$ 1,160,039	\$ 3,183,830	\$ 28,367,351	\$ 457,866	\$ 615,440
Dollars Not Unitized	\$ 1,603,553	\$ 447,082	\$ 602,879	\$ 11,972,807	\$ 83,547	\$ 253,960
2" or Less Ft Per Res. Customer	21	31	38	44	36	68
2" or Less Dollars Per Res Cust.	\$ 8	\$ 570	\$ 283	\$ 517	\$ 294	\$ 315
4" & 6" PE Ft. Per Total Cust.	6	12	10	5.9	32.9	30.2
4" & 6" PE Dollars Per Total Cust.	\$ 71	\$ 608	\$ 159	\$ 160	\$ 328	\$ 334
Services (BI 9608)						
< 2" PE Feet	276,447	46,210	452,894	1,110,523	66,015	39,335
< 2" PE Dollars	\$ 1,098,899	\$ 81,550	\$ 3,821,724	\$ 12,737,724	\$ 375,045	\$ 398,093
Dollars Per Ft	\$ 3.98	\$ 1.76	\$ 8.44	\$ 11.47	\$ 5.68	\$ 10.12
2" & Up PE & Steel Feet	1,499	757	12,520	24	181	2,974
2" PE & Up & Steel Dollars	\$ 12,531	\$ 4,942	\$ 438,431	\$ 2,474,139	\$ 5,141	\$ 5,557
Total Service Footage (Unitized)	277,946	46,210	465,414	1,215,710	66,196	42,309
Total Service Dollars (Unitized)	\$ 1,111,430	\$ 86,492	\$ 4,260,155	\$ 15,211,863	\$ 380,186	\$ 403,649
Total Service Dollars Per Ft	\$ 4.00	\$ 1.87	\$ 9.15	\$ 12.51	\$ 5.74	\$ 9.54
Total Charges to BI 9608 (Incl. O/H)	\$ 1,255,936	\$ 112,854	\$ 4,261,543	\$ 15,366,032	\$ 380,456	\$ 406,229
<2" Ft Per Res. Customer	0	77	79	55	114	72
<2" Dollars Per Res Cust.	\$ 0	\$ 135	\$ 663	\$ 636	\$ 648	\$ 730

SOUTHWEST GAS CORPORATION
ARIZONA
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEAR 2006
RESPONSE TO STAFF DATA REQUEST STF-5-9

Description	Valley	Bullhead City	Tucson	Phoenix	Southeast	Yuma
New Meter Sets	4,583	1,274	8,359	26,459	871	1,225
Residential @ 97% of Total	4,491	1,261	8,108	25,930	810	1,176
Non-Residential @ 3% of Total	92	13	251	529	61	49
Mains (BI 9603)						
2" or Less PE Feet (Unitized)	381,660	46,509	432,835	1,477,530	67,245	48,843
2" or Less PE Dollars (Unitized)	\$ 2,414,837	\$ 398,662	\$ 3,076,161	\$ 16,218,817	\$ 397,389	\$ 302,126
Dollars Per Ft	\$ 6	\$ 9	\$ 7	\$ 10.98	\$ 5.91	\$ 6.19
4" PE Unitized	44,168	16,961	59,926	203,609	18,530	26,305
6" PE Unitized	0	5,860	5,946	64,216	0	0
4" & 6" PE Dollars Unitized	\$ 517,447	\$ 498,715	\$ 904,545	\$ 4,657,428	\$ 188,794	\$ 388,469
4" & 6" PE Dollars Per Ft	\$ 12	\$ 22	\$ 14	\$ 1,831,727	\$ 10.19	\$ 14.77
Steel Ft.	94	0	6	8,121	0	0
Steel Dollar	\$ 1,528	\$ 0	\$ 203	\$ 2,167,563	\$ 0	\$ 0
Steel Dollars Per Ft.	\$ 94	\$ 0	\$ 34	\$ 267	\$ 0	\$ 0
Total Main Footage (Unitized)	425,922	69,330	498,715	1,753,508	85,775	75,148
Total Main Dollars (Unitized)	\$ 2,933,812	\$ 897,385	\$ 3,983,008	\$ 25,277,294	\$ 586,183	\$ 690,671
Total (Unitized) Mains Dollars Per Ft	\$ 7	\$ 13	\$ 8	\$ 14.42	\$ 6.83	\$ 9.19
Total Charges to BI 9603 (Incl. O/H)	\$ 3,220,513	\$ 848,612	\$ 4,983,756	\$ 24,680,452	\$ 617,666	\$ 608,068
Dollars Not Unitized	\$ 286,701	\$ (48,773)	\$ 1,000,748	\$ (596,842)	\$ 31,483	\$ (82,603)
2" or Less Ft Per Res. Customer	85	37	53	57	83	42
2" or Less Dollars Per Res Cust.	\$ 538	\$ 316	\$ 379	\$ 625	\$ 491	\$ 257
4" & 6" PE Ft. Per Total Cust.	10	18	8	10.1	21.3	21.5
4" & 6" PE Dollars Per Total Cust.	\$ 113	\$ 391	\$ 108	\$ 176	\$ 217	\$ 317
Services (BI 9608)						
< 2" PE Feet	142,493	79,699	671,105	850,442	64,178	104,749
< 2" PE Dollars	\$ 1,879,671	\$ 820,857	\$ 5,607,467	\$ 15,518,995	\$ 548,178	\$ 751,276
Dollars Per Ft	\$ 13.19	\$ 10.30	\$ 8.36	\$ 18.25	\$ 8.54	\$ 7.17
2" & Up PE & Steel Feet	247	581	8,804	74,271	2,482	218
2" PE & Up & Steel Dollars	\$ 17,083	\$ 7,767	\$ 241,772	\$ 3,511,932	\$ 43,853	\$ 2,400
Total Service Footage (Unitized)	142,740	80,280	679,909	924,713	66,660	104,967
Total Service Dollars (Unitized)	\$ 1,896,754	\$ 830,101	\$ 5,849,239	\$ 19,030,927	\$ 592,031	\$ 753,676
Total Service Dollars Per Ft	\$ 13.29	\$ 10.34	\$ 8.60	\$ 20.58	\$ 8.88	\$ 7.18
Total Charges to BI 9608 (Incl. O/H)	\$ 1,897,047	\$ 942,464	\$ 5,854,746	\$ 14,191,763	\$ 655,734	\$ 928,874
<2" Ft Per Res. Customer	32	63	83	33	79	89
<2" Dollars Per Res Cust.	\$ 419	\$ 652	\$ 692	\$ 598	\$ 677	\$ 639

SOUTHWEST GAS CORPORATION
ARIZONA
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEAR 2005
RESPONSE TO STAFF DATA REQUEST STF-5-9

Description	Valley	Bullhead City	Tucson	Phoenix	Southeast	Yuma
New Meter Sets	3,503	1,553	8,456	29,051	881	1,468
Residential @ 97% of Total	3,433	1,537	8,202	28,470	819	1,409
Non-Residential @ 3% of Total	70	16	254	581	62	59
Mains (BI 9603)						
2" or Less PE Feet (Unitized)	163,063	64,122	434,123	1,345,297	40,691	94,051
2" or Less PE Dollars (Unitized)	\$ 1,024,247	\$ 471,410	\$ 2,580,826	\$ 13,031,844	\$ 320,211	\$ 301,090
Dollars Per Ft	\$ 6.28	\$ 7.35	\$ 5.94	\$ 9.69	\$ 7.87	\$ 3.20
4" PE Unitized	72,127	10,035	52,849	158,767	14,395	16,755
6" PE Unitized	0	0	6,998	57,842	0	0
4" & 6" PE Dollars Unitized	\$ 612,577	\$ 168,177	\$ 726,796	\$ 5,433,071	\$ 150,418	\$ 200,049
4" & 6" PE Dollars Per Ft	\$ 8	\$ 17	\$ 12.14	\$ 25.08	\$ 10.45	\$ 11.94
Steel Ft.	14,867	0	205	14,479	41,976	0
Steel Dollar	\$ 380,559	\$ 0	\$ (372,316)	\$ 2,643,101	\$ 8,926	\$ 0
Steel Dollars Per Ft.	\$ 26	\$ 0	\$ (1,816)	\$ 183	\$ 0	\$ 0
Total Main Footage (Unitized)	250,057	74,157	494,177	1,576,390	97,062	110,806
Total Main Dollars (Unitized)	\$ 2,018,072	\$ 639,599	\$ 2,937,720	\$ 21,108,016	\$ 479,773	\$ 501,139
(Unitized) Mains Dollars Per Ft	\$ 8.07	\$ 8.62	\$ 5.94	\$ 13.39	\$ 4.94	\$ 4.52
Total Charges to BI 9603 (Incl. O/H)	\$ 2,697,670	\$ 108,846	\$ 3,499,451	\$ 24,680,452	\$ 617,666	\$ 758,920
Dollars Not Unitized	\$ 679,599	\$ (530,753)	\$ 561,731	\$ 3,572,436	\$ 137,893	\$ 257,781
2" or Less Ft Per Res. Customer	47	42	53	47	50	67
2" or Less Dollars Per Res Cust.	\$ 299	\$ 307	\$ 315	\$ 458	\$ 391	\$ 214
4" & 6" PE Ft. Per Total Cust.	20.6	6.5	7.1	7.5	16.3	11.4
4" & 6" PE Dollars Per Total Cust.	\$ 175	\$ 108	\$ 86	\$ 187	\$ 171	\$ 136
Services (BI 9608)						
< 2" PE Feet	77,879	91,275	394,297	939,278	44,657	41,437
< 2" PE Dollars	\$ 1,241,077	\$ 1,153,192	\$ 4,597,732	\$ 12,249,491	\$ 571,249	\$ 876,067
Dollars Per Ft	\$ 15.94	\$ 12.63	\$ 11.66	\$ 13.04	\$ 12.79	\$ 21.14
2" & Up PE & Steel Feet	8,647	1,829	11,304	82,372	4,132	718
2" PE & Up & Steel Dollars	\$ 56,326	\$ 8,462	\$ 257,599	\$ 1,947,538	\$ 84,773	\$ 46,778
Total Service Footage (Unitized)	86,526	93,104	405,601	1,021,650	48,789	42,155
Total Service Dollars (Unitized)	\$ 1,297,403	\$ 1,163,130	\$ 4,855,331	\$ 14,197,029	\$ 656,022	\$ 922,845
Total Service Dollars Per Ft	\$ 14.99	\$ 12.49	\$ 11.97	\$ 13.90	\$ 13.45	\$ 21.89
Total Charges to BI 9608 (Incl. O/H)	\$ 1,297,403	\$ 1,165,010	\$ 4,852,492	\$ 14,191,763	\$ 655,734	\$ 928,874
<2" Ft Per Res. Customer	23	59	48	33	55	29
<2" Dollars Per Res Cust.	\$ 362	\$ 751	\$ 561	\$ 430	\$ 697	\$ 622

**SOUTHWEST GAS CORPORATION
ARIZONA
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEAR 2004
RESPONSE TO STAFF DATA REQUEST STF-5-9**

Description	Valley	Bullhead City	Tucson	Phoenix	Southeast	Yuma
New Meter Sets	1,907	1,128	8,279	29,858	954	1,237
Residential @ 97% of Total	1,869	1,117	8,031	29,261	887	1,188
Non-Residential @ 3% of Total	38	11	248	597	67	49
Mains (BI 9603)						
2" or Less PE Feet (Unitized)	201,743	47,088	382,191	1,643,344	52,088	95,025
2" or Less PE Dollars (Unitized)	\$ 1,322,011	\$ 355,717	\$ 2,853,682	\$ 15,729,998	\$ 319,381	\$ 561,943
Dollars Per Ft	\$ 6.55	\$ 7.55	\$ 7.47	\$ 9.57	\$ 6.13	\$ 5.91
4" PE Unitized	26,936	12,482	69,062	233,458	10,812	29,953
6" PE Unitized	0	2,489	0	114,124	0	0
4" & 6" PE Dollars Unitized	\$ 279,265	\$ 300,383	\$ 805,650	\$ 10,667,814	\$ 90,454	\$ 338,681
4" & 6" PE Dollars Per Ft	\$ 10	\$ 20	\$ 11.67	\$ 30.69	\$ 8.37	\$ 11.31
Steel Ft.	0	0	1,365	66,609	0	97
Steel Dollar	\$ 0	\$ 0	\$ 41,125	\$ 5,076,329	\$ 0	\$ 4,806
Steel Dollars Per Ft.	\$ #DIV/0!	\$ 0	\$ 30	\$ 76	\$ 0	\$ 0
Total Main Footage (Unitized)	228,679	62,059	452,618	2,057,589	62,900	125,161
Total Main Dollars (Unitized)	\$ 1,601,277	\$ 656,100	\$ 3,700,457	\$ 31,474,141	\$ 409,835	\$ 908,248
Total (Unitized) Mains Dollars Per Ft	\$ 7.00	\$ 10.57	\$ 8.18	\$ 15.30	\$ 6.52	\$ 7.26
Total Charges to BI 9603 (Incl. O/H)	\$ 1,900,024	\$ 708,956	\$ 3,579,100	\$ 29,275,579	\$ 422,289	\$ 1,046,217
Dollars Not Unitized	\$ 298,747	\$ 52,856	\$ (121,357)	\$ (2,198,562)	\$ 12,454	\$ 137,969
2" or Less Ft Per Res. Customer	108	42	48	56	59	80
2" or Less Dollars Per Res Cust.	\$ 707	\$ 319	\$ 355	\$ 538	\$ 360	\$ 473
4" & 6" PE Ft. Per Total Cust.	14.1	13.3	8.3	11.6	11.3	24.2
4" & 6" PE Dollars Per Total Cust.	\$ 146	\$ 266	\$ 97	\$ 357	\$ 95	\$ 274
Services (BI 9608)						
< 2" PE Feet	101,827	44,234	471,984	1,427,334	67,574	58,862
< 2" PE Dollars	\$ 866,800	\$ 1,052,956	\$ 4,348,654	\$ 13,384,902	\$ 576,381	\$ 722,068
Dollars Per Ft	\$ 8.51	\$ 23.80	\$ 9.21	\$ 9.38	\$ 8.53	\$ 12.27
2" & Up PE & Steel Feet	1,326	0	8,776	123,518	3,292	1,065
2" PE & Up & Steel Dollars	\$ 17,611	\$ 0	\$ 214,246	\$ 2,277,714	\$ 41,430	\$ (10,490)
Total Service Footage (Unitized)	103,153	44,234	480,760	1,550,852	70,866	59,927
Total Service Dollars (Unitized)	\$ 884,412	\$ 1,057,338	\$ 4,562,973	\$ 15,662,616	\$ 617,811	\$ 711,579
Total Service Dollars Per Ft	\$ 8.57	\$ 23.90	\$ 9.49	\$ 10.10	\$ 8.72	\$ 11.87
Total Charges to BI 9608 (Incl. O/H)	\$ 1,005,851	\$ 1,064,338	\$ 4,604,204	\$ 15,778,037	\$ 620,698	\$ 787,071
<2" Ft Per Res. Customer	54	40	59	49	76	50
<2" Dollars Per Res Cust.	\$ 464	\$ 947	\$ 542	\$ 457	\$ 650	\$ 608

SOUTHWEST GAS CORPORATION
ARIZONA
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEAR 2003
RESPONSE TO STAFF DATA REQUEST STF-5-9

Description	Valley	Bullhead City	Tucson	Phoenix	Southeast	Yuma
<u>New Meter Sets</u>	1,135	732	7,721	26,583	753	1,147
Residential @ 97% of Total	1,112	725	7,489	26,051	700	1,101
Non-Residential @ 3% of Total	23	7	232	532	53	46
<u>Mains (BI 9603)</u>						
2" or Less PE Feet (Unitized)	114,147	31,524	393,072	1,697,113	50,763	51,126
2" or Less PE Dollars (Unitized)	\$ 673,806	\$ 330,105	\$ 2,509,788	\$ 15,423,483	\$ 285,956	\$ 345,382
Dollars Per Ft	\$ 5.90	\$ 10.47	\$ 6.39	\$ 9.09	\$ 5.63	\$ 6.76
4" PE Unitized	44,685	5,296	80,508	246,355	4,130	25,224
6" PE Unitized	0	0	22	107,135	0	0
4" & 6" PE Dollars Unitized	\$ 305,184	\$ 61,010	\$ 874,764	\$ 9,790,499	\$ 58,367	\$ 313,132
4" & 6" PE Dollars Per Ft	\$ 7	\$ 12	\$ 10.86	\$ 27.70	\$ 14.13	\$ 12.41
Steel Ft.	1	0	3,119	48,343	1,807	499
Steel Dollar	\$ 70	\$ 0	\$ 69,263	\$ 2,935,205	\$ 72,596	\$ 28,950
Steel Dollars Per Ft.	\$ 70	\$ 0	\$ 22	\$ 48,343	\$ 40	\$ 58
Total Main Footage (Unitized)	158,833	36,820	476,721	2,098,958	56,700	77,258
Total Main Dollars (Unitized)	\$ 979,060	\$ 391,114	\$ 3,453,815	\$ 28,149,187	\$ 416,919	\$ 698,492
Total (Unitized) Mains Dollars Per Ft	\$ 6.16	\$ 10.62	\$ 7.24	\$ 13.41	\$ 7.35	\$ 9.04
Total Charges to BI 9603 (Incl. O/H)	\$ 908,624	\$ 402,207	\$ 3,493,893	\$ 30,116,014	\$ 444,646	\$ 691,824
Dollars Not Unitized	\$ (70,436)	\$ 11,093	\$ 40,078	\$ 1,966,827	\$ 27,727	\$ (6,668)
2" or Less Ft Per Res. Customer	103	44	52	65	72	46
2" or Less Dollars Per Res Cust.	\$ 606	\$ 456	\$ 335	\$ 592	\$ 408	\$ 314
4" & 6" PE Ft. Per Total Cust.	39.4	7.2	10.4	13.3	5.5	22.0
4" & 6" PE Dollars Per Total Cust.	\$ 269	\$ 83	\$ 113	\$ 368	\$ 78	\$ 273
<u>Services (BI 9608)</u>						
< 2" PE Feet	31,844	45,915	583,200	1,320,296	69,268	54,391
< 2" PE Dollars	\$ 694,758	\$ 587,596	\$ 4,531,804	\$ 12,980,819	\$ 474,816	\$ 788,030
Dollars Per Ft	\$ 21.82	\$ 12.80	\$ 7.77	\$ 9.83	\$ 6.85	\$ 14.49
2" & Up PE & Steel Feet	1,592	585	27,170	159,311	3,249	429
2" PE & Up & Steel Dollars	\$ 55,232	\$ 401	\$ 442,776	\$ 3,224,697	\$ 55,036	\$ 1,513
Total Service Footage (Unitized)	33,436	46,500	610,370	1,479,607	72,517	54,820
Total Service Dollars (Unitized)	\$ 749,990	\$ 590,793	\$ 4,987,511	\$ 16,205,516	\$ 529,852	\$ 789,543
Total Service Dollars Per Ft	\$ 22.43	\$ 12.71	\$ 8.17	\$ 10.95	\$ 7.31	\$ 14.40
Total Charges to BI 9608 (Incl. O/H)	\$ 752,124	\$ 600,795	\$ 4,988,202	\$ 16,194,961	\$ 529,860	\$ 794,854
<2" Ft Per Res. Customer	29	63	78	51	99	49
<2" Dollars Per Res Cust.	\$ 625	\$ 815	\$ 607	\$ 498	\$ 678	\$ 716

SOUTHWEST GAS CORPORATION
ARIZONA
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEAR 2002
RESPONSE TO STAFF DATA REQUEST STF-5-9

Description	Valley	Bullhead City	Tucson	Phoenix	Southeast	Yuma
New Meter Sets	645	526	7,545	23,987	750	898
Residential @ 97% of Total	632	521	7,319	23,267	698	862
Non-Residential @ 3% of Total	13	5	226	720	53	36
Mains (BI 9603)						
2" or Less PE Feet (Unitized)	68,386	23,713	390,241	1,385,477	59,678	82,665
2" or Less PE Dollars (Unitized)	\$ 587,086	\$ 257,937	\$ 3,610,865	\$ 14,722,689	\$ 380,384	\$ 595,067
Dollars Per Ft	\$ 8.58	\$ 10.88	\$ 9.25	\$ 10.63	\$ 6.37	\$ 7.20
4" PE Unitized	36,047	544	108,200	309,308	5,763	18,328
6" PE Unitized	0	0	11,079	83,571	0	0
4" & 6" PE Dollars Unitized	\$ 319,613	\$ 14,076	\$ 1,601,446	\$ 11,323,934	\$ 56,307	\$ 250,954
4" & 6" PE Dollars Per Ft	\$ 9	\$ 26	\$ 13.43	\$ 28.82	\$ 9.77	\$ 13.69
Steel Ft.	23,751	0	10,628	38,217	114	20
Steel Dollar	\$ 1,039,083	\$ 0	\$ 365,059	\$ 1,559,025	\$ 1,585	\$ 765
Steel Dollars Per Ft.	\$ 44	\$ 0	\$ 34	\$ 41	\$ 14	\$ 38
Total Main Footage (Unitized)	128,590	24,257	520,156	1,816,582	65,555	101,013
Total Main Dollars (Unitized)	\$ 2,146,977	\$ 272,013	\$ 5,592,729	\$ 27,605,648	\$ 438,277	\$ 846,786
Total (Unitized) Mains Dollars Per Ft	\$ 16.70	\$ 11.21	\$ 10.75	\$ 15.20	\$ 6.69	\$ 8.38
Total Charges to BI 9603 (Incl. O/H)	\$ 2,189,554	\$ 300,986	\$ 6,007,184	\$ 28,954,626	\$ 422,237	\$ 831,648
Dollars Not Unitized	\$ 42,577	\$ 28,973	\$ 414,455	\$ 1,348,978	\$ (16,040)	\$ (15,138)
2" or Less Ft Per Res. Customer	108	46	53	60	86	96
2" or Less Dollars Per Res Cust.	\$ 929	\$ 495	\$ 493	\$ 633	\$ 545	\$ 690
4" & 6" PE Ft. Per Total Cust.	55.9	1.0	15.8	16.4	7.7	20.4
4" & 6" PE Dollars Per Total Cust.	\$ 496	\$ 27	\$ 212	\$ 472	\$ 75	\$ 279
Services (BI 9608)						
< 2" PE Feet	68,386	23,713	390,241	1,385,477	66,162	67,574
< 2" PE Dollars	\$ 678,764	\$ 513,712	\$ 4,069,600	\$ 10,154,595	\$ 486,741	\$ 642,897
Dollars Per Ft	\$ 9.93	\$ 21.66	\$ 10.43	\$ 7.33	\$ 7.36	\$ 9.51
2" & Up PE & Steel Feet	3,833	592	36,107	168,143	4,149	1,350
2" PE & Up & Steel Dollars	\$ 166,954	\$ 31,272	\$ 979,974	\$ 7,425,013	\$ 87,635	\$ 65,256
Total Service Footage (Unitized)	70,354	38,678	558,967	1,258,007	70,311	68,924
Total Service Dollars (Unitized)	\$ 845,718	\$ 548,319	\$ 5,064,999	\$ 17,579,608	\$ 574,376	\$ 708,153
Total Service Dollars Per Ft	\$ 12.02	\$ 14.18	\$ 9.06	\$ 13.97	\$ 8.17	\$ 10.27
Total Charges to BI 9608 (Incl. O/H)	\$ 846,768	\$ 548,326	\$ 5,067,630	\$ 17,644,704	\$ 574,385	\$ 713,503
<2" Ft Per Res. Customer	105	73	71	47	95	78
<2" Dollars Per Res Cust.	\$ 1,074	\$ 993	\$ 558	\$ 436	\$ 698	\$ 746

**SOUTHWEST GAS CORPORATION
ARIZONA
DISTRICT 32 VALLEY
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEARS ENDED DECEMBER 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9**

Description	2007	2006	2005	2004	2003	2002
<u>New Meter Sets</u>	2,904	4,583	3,503	1,907	1,135	645
Residential @ 97% of Total	2,846	4,491	3,433	1,869	1,112	632
Non-Residential @ 3% of Total	58	92	70	38	23	13
<u>Mains (BI 9603)</u>						
2" or Less PE Feet (Unitized)	58,376	381,660	163,063	201,743	114,147	68,386
2" or Less PE Dollars (Unitized)	\$ 23,724	\$ 2,414,837	\$ 1,024,247	\$ 1,322,011	\$ 673,806	\$ 587,086
Dollars Per Ft	\$ 0.41	\$ 6.33	\$ 6.28	\$ 6.55	\$ 5.90	\$ 8.58
4" PE	17,280	44,168	72,127	26,936	44,685	36,047
6" PE	0	0	0	0	0	0
4" & 6" PE Dollars	\$ 206,444	\$ 517,447	\$ 612,577	\$ 279,265	\$ 305,184	\$ 319,613
4" & 6" PE Dollars Per Ft	\$ 11.95	\$ 11.72	\$ 8.49	\$ 10.37	\$ 6.83	\$ 8.87
Steel Ft.	94	94	14,867	0	1	23,751
Steel Dollar	\$ 1,528	\$ 1,528	\$ 380,559	\$ 0	\$ 70	\$ 1,039,083
Steel Dollars Per Ft.	\$ 1,528.41	\$ 94.00	\$ 25.60	\$ #DIV/0!	\$ 69.62	\$ 43.75
Total Main Footage (Unitized)	75,750	425,922	250,057	228,679	158,833	128,590
Total Main Dollars (Unitized)	\$ 231,696	\$ 2,933,812	\$ 2,018,072	\$ 1,601,277	\$ 979,060	\$ 2,146,977
Total (Unitized) Mains Dollars Per Ft	\$ 3.06	\$ 6.89	\$ 8.07	\$ 7.00	\$ 6.16	\$ 16.70
Total Charges to BI 9603 (Incl. O/H)	\$ 1,835,250	\$ 3,220,513	\$ 2,697,670	\$ 1,900,024	\$ 908,624	\$ 2,189,554
Dollars Not Unitized	\$ 1,603,553	\$ 286,701	\$ 679,599	\$ 298,747	\$ (70,436)	\$ 42,577
2" or Less Ft Per Res. Customer	21	85	47	108	103	108
Unitized 2" or Less \$ Per Res Cust.	\$ 8	\$ 538	\$ 299	\$ 707	\$ 606	\$ 929
4" & 6" PE Ft. Per Total Cust.	6.0	9.6	20.6	14.1	39.4	55.9
4" & 6" PE Dollars Per Total Cust.	\$ 71	\$ 113	\$ 175	\$ 146	\$ 269	\$ 496
<u>Services (BI 9608)</u>						
< 2" PE Feet	276,447	142,493	77,879	101,827	31,844	68,386
< 2" PE Dollars	\$ 1,098,899	\$ 1,879,671	\$ 1,241,077	\$ 866,800	\$ 694,758	\$ 678,764
Dollars Per Ft	\$ 3.98	\$ 13.19	\$ 15.94	\$ 8.51	\$ 21.82	\$ 9.93
2" & Up PE & Steel Feet	1,499	247	8,647	1,326	1,592	3,833
2" PE & Up & Steel Dollars	\$ 12,531	\$ 17,083	\$ 56,326	\$ 17,611	\$ 55,232	\$ 166,954
Total Service Footage (Unitized)	277,946	142,740	86,526	103,153	33,436	70,354
Total Service Dollars (Unitized)	\$ 1,111,430	\$ 1,896,754	\$ 1,297,403	\$ 884,412	\$ 749,990	\$ 845,718
Total Service Dollars Per Ft	\$ 4.00	\$ 13.29	\$ 14.99	\$ 8.57	\$ 22.43	\$ 12.02
Total Charges to BI 9608 (Incl. O/H)	\$ 1,255,936	\$ 1,897,047	\$ 1,297,403	\$ 1,005,851	\$ 752,124	\$ 846,768
<2" Ft Per Res. Customer	0	32	23	54	29	105
<2" Dollars Per Res Cust.	\$ 0	\$ 419	\$ 362	\$ 464	\$ 625	\$ 1,074

**SOUTHWEST GAS CORPORATION
DISTRICT 34 BULLHEAD CITY
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEARS ENDED DECEMBER 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9**

Description	2007	2006	2005	2004	2003	2002
New Meter Sets	608	1,274	1,553	1,128	732	526
Residential @ 97% of Total	602	1,261	1,537	1,117	725	521
Non-Residential @ 3% of Total	6	13	16	11	7	5
Mains (BI 9603)						
2" or Less PE Feet (Unitized)	18,400	46,509	64,122	47,088	31,524	23,713
2" or Less PE Dollars (Unitized)	\$ 343,196	\$ 398,662	\$ 471,410	\$ 355,717	\$ 330,105	\$ 257,937
Dollars Per Ft	\$ 18.65	\$ 8.57	\$ 7.35	\$ 7.55	\$ 10.47	\$ 10.88
4" PE	7,331	16,961	10,035	12,482	5,296	544
6" PE	0	5,860	0	2,489	0	0
4" & 6" PE Dollars	\$ 369,753	\$ 498,715	\$ 168,177	\$ 300,383	\$ 61,010	\$ 14,076
4" & 6" PE Dollars Per Ft	\$ 50.44	\$ 21.85	\$ 16.76	\$ 20.06	\$ 11.52	\$ 25.87
Steel Ft.	0	0	0	0	0	0
Steel Dollar	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Steel Dollars Per Ft.	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00
Total Main Footage (Unitized)	25,731	69,330	74,157	62,059	36,820	24,257
Total Main Dollars (Unitized)	\$ 712,957	\$ 897,385	\$ 639,599	\$ 656,100	\$ 391,114	\$ 272,013
Total (Unitized) Mains Dollars Per Ft	\$ 27.71	\$ 12.94	\$ 8.62	\$ 10.57	\$ 10.62	\$ 11.21
Total Charges to BI 9603 (Incl. O/H)	\$ 1,160,039	\$ 848,612	\$ 108,846	\$ 708,956	\$ 402,207	\$ 300,986
Dollars Not Unitized	\$ 447,082	\$ (48,773)	\$ (530,753)	\$ 52,856	\$ 11,093	\$ 28,973
2" or Less Ft Per Res. Customer	31	37	42	42	44	46
Unitized 2" or Less \$ Per Res Cust.	\$ 570	\$ 316	\$ 307	\$ 319	\$ 456	\$ 495
4" & 6" PE Ft. Per Total Cust.	12.1	17.9	6.5	13.3	7.2	1.0
4" & 6" PE Dollars Per Total Cust.	\$ 608	\$ 391	\$ 108	\$ 266	\$ 83	\$ 27
Services (BI 9608)						
< 2" PE Feet	46,210	79,699	91,275	44,234	45,915	23,713
< 2" PE Dollars	\$ 81,550	\$ 820,857	\$ 1,153,192	\$ 1,052,956	\$ 587,596	\$ 513,712
Dollars Per Ft	\$ 1.76	\$ 10.30	\$ 12.63	\$ 23.80	\$ 12.80	\$ 21.66
2" & Up PE & Steel Feet	757	581	1,829	0	585	592
2" PE & Up & Steel Dollars	\$ 4,942	\$ 7,767	\$ 8,462	\$ 0	\$ 401	\$ 31,272
Total Service Footage (Unitized)	46,210	80,280	93,104	44,234	46,500	38,678
Total Service Dollars (Unitized)	\$ 86,492	\$ 830,101	\$ 1,163,130	\$ 1,057,338	\$ 590,793	\$ 548,319
Total Service Dollars Per Ft	\$ 1.87	\$ 10.34	\$ 12.49	\$ 23.90	\$ 12.71	\$ 14.18
Total Charges to BI 9608 (Incl. O/H)	\$ 112,854	\$ 942,464	\$ 1,165,010	\$ 1,064,338	\$ 600,795	\$ 548,326
<2" Ft Per Res. Customer	77	63	59	40	63	73
<2" Dollars Per Res Cust.	\$ 135	\$ 652	\$ 751	\$ 947	\$ 815	\$ 993

SOUTHWEST GAS CORPORATION
ARIZONA
DISTRICT 36 TUCSON
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEARS ENDED DECEMBER 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9

Description	2007	2006	2005	2004	2003	2002
<u>New Meter Sets</u>	5,945	8,359	8,456	8,279	7,721	7,545
Residential @ 97% of Total	5,767	8,108	8,202	8,031	7,489	7,319
Non-Residential @ 3% of Total	178	251	254	248	232	226
<u>Mains (BI 9603)</u>						
2" or Less PE Feet (Unitized)	220,646	432,835	434,123	382,191	393,072	390,241
2" or Less PE Dollars (Unitized)	\$ 1,632,137	\$ 3,076,161	\$ 2,580,826	\$ 2,853,682	\$ 2,509,788	\$ 3,610,865
Dollars Per Ft	\$ 7.40	\$ 7.11	\$ 5.94	\$ 7.47	\$ 6.39	\$ 9.25
4" PE	51,973	59,926	52,849	69,062	80,508	108,200
6" PE	6,028	5,946	6,998	0	22	11,079
4" & 6" PE Dollars	\$ 943,349	\$ 904,545	\$ 726,796	\$ 805,650	\$ 874,764	\$ 1,601,446
4" & 6" PE Dollars Per Ft	\$ 16.26	\$ 13.73	\$ 12.14	\$ 11.67	\$ 10.86	\$ 13.43
Steel Ft.	6	6	205	1,365	3,119	10,628
Steel Dollar	\$ 452	\$ 203	\$ (372,316)	\$ 41,125	\$ 69,263	\$ 365,059
Steel Dollars Per Ft.	\$ 202.85	\$ 33.81	\$ (1,816.17)	\$ 30.13	\$ 22.21	\$ 34.35
Total Main Footage (Unitized)	278,657	498,715	494,177	452,618	476,721	520,156
Total Main Dollars (Unitized)	\$ 2,580,951	\$ 3,983,008	\$ 2,937,720	\$ 3,700,457	\$ 3,453,815	\$ 5,592,729
Total (Unitized) Mains Dollars Per Ft	\$ 9.26	\$ 7.99	\$ 5.94	\$ 8.18	\$ 7.24	\$ 10.75
Total Charges to BI 9603 (Incl. O/H)	\$ 3,183,830	\$ 4,983,756	\$ 3,499,451	\$ 3,579,100	\$ 3,493,893	\$ 6,007,184
Dollars Not Unitized	\$ 602,879	\$ 1,000,748	\$ 561,731	\$ (121,357)	\$ 40,078	\$ 414,455
2" or Less Ft Per Res. Customer	38	53	53	48	52	53
Unitized 2" or Less \$ Per Res Cust.	\$ 283	\$ 379	\$ 315	\$ 355	\$ 335	\$ 493
4" & 6" PE Ft. Per Total Cust.	9.8	7.9	7.1	8.3	10.4	15.8
4" & 6" PE Dollars Per Total Cust.	\$ 159	\$ 108	\$ 86	\$ 97	\$ 113	\$ 212
<u>Services (BI 9608)</u>						
< 2" PE Feet	452,894	671,105	394,297	471,984	583,200	390,241
< 2" PE Dollars	\$ 3,821,724	\$ 5,607,467	\$ 4,597,732	\$ 4,348,654	\$ 4,531,804	\$ 4,069,600
Dollars Per Ft	\$ 8.44	\$ 8.36	\$ 11.66	\$ 9.21	\$ 7.77	\$ 10.43
2" & Up PE & Steel Feet	12,520	8,804	11,304	8,776	27,170	36,107
2" PE & Up & Steel Dollars	\$ 438,431	\$ 241,772	\$ 257,599	\$ 214,246	\$ 442,776	\$ 979,974
Total Service Footage (Unitized)	465,414	679,909	405,601	480,760	610,370	558,967
Total Service Dollars (Unitized)	\$ 4,260,155	\$ 5,849,239	\$ 4,855,331	\$ 4,562,973	\$ 4,987,511	\$ 5,064,999
Total Service Dollars Per Ft	\$ 9.15	\$ 8.60	\$ 11.97	\$ 9.49	\$ 8.17	\$ 9.06
Total Charges to BI 9608 (Incl. O/H)	\$ 4,261,543	\$ 5,854,746	\$ 4,852,492	\$ 4,604,204	\$ 4,988,202	\$ 5,067,630
<2" Ft Per Res. Customer	79	83	48	59	78	71
<2" Dollars Per Res Cust.	\$ 663	\$ 692	\$ 561	\$ 542	\$ 607	\$ 558

SOUTHWEST GAS CORPORATION
ARIZONA
DISTRICT 42 PHOENIX
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEARS ENDED DECEMBER 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9

Description	2007	2006	2005	2004	2003	2002
<u>New Meter Sets</u>	20,446	26,459	29,051	29,858	26,583	23,987
Residential @ 97% of Total	20,037	25,930	28,470	29,261	26,051	23,267
Non-Residential @ 3% of Total	409	529	581	597	532	720
<u>Mains (BI 9603)</u>						
2" or Less PE Feet (Unitized)	883,042	1,477,530	1,345,297	1,643,344	1,697,113	1,385,477
2" or Less PE Dollars (Unitized)	\$ 10,364,664	\$ 16,218,817	\$ 13,031,844	\$ 15,729,998	\$ 15,423,483	\$ 14,722,689
Dollars Per Ft	\$ 11.74	\$ 10.98	\$ 9.69	\$ 9.57	\$ 9.09	\$ 10.63
4" PE	91,623	203,609	158,767	233,458	246,355	309,308
6" PE	29,732	64,216	57,842	114,124	107,135	83,571
4" & 6" PE Dollars	\$ 3,274,354	\$ 4,657,428	\$ 5,433,071	\$ 10,667,814	\$ 9,790,499	\$ 11,323,934
4" & 6" PE Dollars Per Ft	\$ 842,191	\$ 1,831,727	\$ 25.08	\$ 30.69	\$ 27.70	\$ 28.82
Steel Ft.	7,663	8,121	14,479	66,609	48,343	38,217
Steel Dollar	\$ 1,874,486	\$ 2,167,563	\$ 2,643,101	\$ 5,076,329	\$ 2,935,205	\$ 1,559,025
Steel Dollars Per Ft.	\$ 244.62	\$ 266.91	\$ 182.55	\$ 76.21	\$ 48,343.00	\$ 40.79
Total Main Footage (Unitized)	1,012,070	1,753,508	1,576,390	2,057,589	2,098,958	1,816,582
Total Main Dollars (Unitized)	\$ 16,394,544	\$ 25,277,294	\$ 21,108,016	\$ 31,474,141	\$ 28,149,187	\$ 27,605,648
Total (Unitized) Mains \$ Per Ft	\$ 16.20	\$ 14.42	\$ 13.39	\$ 15.30	\$ 13.41	\$ 15.20
Total Charges to BI 9603 (Incl. O/H)	\$ 28,367,351	\$ 24,680,452	\$ 24,680,452	\$ 29,275,579	\$ 30,116,014	\$ 28,954,626
Dollars Not Unitized	\$ 11,972,807	\$ (596,842)	\$ 3,572,436	\$ (2,198,562)	\$ 1,966,827	\$ 1,348,978
2" or Less Ft Per Res. Customer	44	57	47	56	65	60
2" or Less Dollars Per Res Cust.	\$ 517	\$ 625	\$ 458	\$ 538	\$ 592	\$ 633
4" & 6" PE Ft. Per Total Cust.	5.9	10.1	7.5	11.6	13.3	16.4
4" & 6" PE Dollars Per Total Cust.	\$ 160	\$ 176	\$ 187	\$ 357	\$ 368	\$ 472
<u>Services (BI 9608)</u>						
< 2 " PE Feet	1,110,523	850,442	939,278	1,427,334	1,320,296	1,385,477
< 2" PE Dollars	\$ 12,737,724	\$ 15,518,995	\$ 12,249,491	\$ 13,384,902	\$ 12,980,819	\$ 10,154,595
Dollars Per Ft	\$ 11.47	\$ 18.25	\$ 13.04	\$ 9.38	\$ 9.83	\$ 7.33
2" & Up PE & Steel Feet	24	74,271	82,372	123,518	159,311	168,143
2" PE & Up & Steel Dollars	\$ 2,474,139	\$ 3,511,932	\$ 1,947,538	\$ 2,277,714	\$ 3,224,697	\$ 7,425,013
Total Service Footage (Unitized)	1,215,710	924,713	1,021,650	1,550,852	1,479,607	1,258,007
Total Service Dollars (Unitized)	\$ 15,211,863	\$ 19,030,927	\$ 14,197,029	\$ 15,662,616	\$ 16,205,516	\$ 17,579,608
Total Service Dollars Per Ft	\$ 12.51	\$ 20.58	\$ 13.90	\$ 10.10	\$ 10.95	\$ 13.97
Total Charges to BI 9608 (Incl. O/H)	\$ 15,366,032	\$ 14,191,763	\$ 14,191,763	\$ 15,778,037	\$ 16,194,961	\$ 17,644,704
<2" Ft Per Res. Customer	55	33	33	49	51	47
<2" Dollars Per Res Cust.	\$ 636	\$ 598	\$ 430	\$ 457	\$ 498	\$ 436

SOUTHWEST GAS CORPORATION
ARIZONA
DISTRICT 47 SOUTHEAST
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEARS ENDED DECEMBER 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9

Description	2007	2006	2005	2004	2003	2002
New Meter Sets	622	871	881	954	753	750
Residential @ 97% of Total	578	810	819	887	700	698
Non-Residential @ 3% of Total	44	61	62	67	53	53
Mains (BI 9603)						
2" or Less PE Feet (Unitized)	20,869	67,245	40,691	52,088	50,763	59,678
2" or Less PE Dollars (Unitized)	\$ 170,352	\$ 397,389	\$ 320,211	\$ 319,381	\$ 285,956	\$ 380,384
Dollars Per Ft	\$ 8.16	\$ 5.91	\$ 7.87	\$ 6.13	\$ 5.63	\$ 6.37
4" PE	20,447	18,530	14,395	10,812	4,130	5,763
6" PE	0	0	0	0	0	0
4" & 6" PE Dollars	\$ 203,967	\$ 188,794	\$ 150,418	\$ 90,454	\$ 58,367	\$ 56,307
4" & 6" PE Dollars Per Ft	\$ 9.98	\$ 10.19	\$ 10.45	\$ 8.37	\$ 14.13	\$ 9.77
Steel Ft.	0	0	41,976	0	1,807	114
Steel Dollar	\$ 0	\$ 0	\$ 8,926	\$ 0	\$ 72,596	\$ 1,585
Steel Dollars Per Ft.	\$ 0.00	\$ 0.00	\$ 0.21	\$ 0.00	\$ 40.17	\$ 13.91
Total Main Footage (Unitized)	41,316	85,775	97,062	62,900	56,700	65,555
Total Main Dollars (Unitized)	\$ 374,319	\$ 586,183	\$ 479,773	\$ 409,835	\$ 416,919	\$ 438,277
Total (Unitized) Mains \$ Per Ft	\$ 9.06	\$ 6.83	\$ 4.94	\$ 6.52	\$ 7.35	\$ 6.69
Total Charges to BI 9603 (Incl. O/H)	\$ 457,866	\$ 617,666	\$ 617,666	\$ 422,289	\$ 444,646	\$ 422,237
Dollars Not Unitized	\$ 83,547	\$ 31,483	\$ 137,893	\$ 12,454	\$ 27,727	\$ (16,040)
2" or Less Ft Per Res. Customer	36	83	50	59	72	86
Unitized 2" or Less \$ Per Res Cust.	\$ 294	\$ 491	\$ 391	\$ 360	\$ 408	\$ 545
4" & 6" PE Ft. Per Total Cust.	32.9	21.3	16.3	11.3	5.5	7.7
4" & 6" PE Dollars Per Total Cust.	\$ 328	\$ 217	\$ 171	\$ 95	\$ 78	\$ 75
Services (BI 9608)						
< 2" PE Feet	66,015	64,178	44,657	67,574	69,268	66,162
< 2" PE Dollars	\$ 375,045	\$ 548,178	\$ 571,249	\$ 576,381	\$ 474,816	\$ 486,741
Dollars Per Ft	\$ 5.68	\$ 8.54	\$ 12.79	\$ 8.53	\$ 6.85	\$ 7.36
2" & Up PE & Steel Feet	181	2,482	4,132	3,292	3,249	4,149
2" PE & Up & Steel Dollars	\$ 5,141	\$ 43,853	\$ 84,773	\$ 41,430	\$ 55,036	\$ 87,635
Total Service Footage (Unitized)	66,196	66,660	48,789	70,866	72,517	70,311
Total Service Dollars (Unitized)	\$ 380,186	\$ 592,031	\$ 656,022	\$ 617,811	\$ 529,852	\$ 574,376
Total Service Dollars Per Ft	\$ 5.74	\$ 8.88	\$ 13.45	\$ 8.72	\$ 7.31	\$ 8.17
Total Charges to BI 9608 (Incl. O/H)	\$ 380,456	\$ 655,734	\$ 655,734	\$ 620,698	\$ 529,860	\$ 574,385
<2" Ft Per Res. Customer	114	79	55	76	99	95
<2" Dollars Per Res Cust.	\$ 648	\$ 677	\$ 697	\$ 650	\$ 678	\$ 698

**SOUTHWEST GAS CORPORATION
ARIZONA
DISTRICT 48 YUMA
NEW CUSTOMER CAPITAL STATISTICS
BI NUMBERS 9603 MAINS AND 9608 SERVICES
FOR THE YEARS ENDED DECEMBER 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9**

Description	2007	2006	2005	2004	2003	2002
<u>New Meter Sets</u>	568	1,225	1,468	1,237	1,147	898
Residential @ 97% of Total	545	1,176	1,409	1,188	1,101	862
Non-Residential @ 3% of Total	23	49	59	49	46	36
<u>Mains (BI 9603)</u>						
2" or Less PE Feet (Unitized)	36,993	48,843	94,051	95,025	51,126	82,665
2" or Less PE Dollars (Unitized)	\$ 171,899	\$ 302,126	\$ 301,090	\$ 561,943	\$ 345,382	\$ 595,067
Dollars Per Ft	\$ 4.65	\$ 6.19	\$ 3.20	\$ 5.91	\$ 6.76	\$ 7.20
4" PE	17,128	26,305	16,755	29,953	25,224	18,328
6" PE	0	0	0	0	0	0
4" & 6" PE Dollars	\$ 189,479	\$ 388,469	\$ 200,049	\$ 338,681	\$ 313,132	\$ 250,954
4" & 6" PE Dollars Per Ft	\$ 11.06	\$ 14.77	\$ 11.94	\$ 11.31	\$ 12.41	\$ 13.69
Steel Ft.	0	0	0	97	499	20
Steel Dollar	\$ 0	\$ 0	\$ 0	\$ 4,806	\$ 28,950	\$ 765
Steel Dollars Per Ft.	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 58.02	\$ 38.23
Total Main Footage (Unitized)	54,121	75,148	110,806	125,161	77,258	101,013
Total Main Dollars (Unitized)	\$ 361,480	\$ 690,671	\$ 501,139	\$ 908,248	\$ 698,492	\$ 846,786
Total (Unitized) Mains Dollars Per Ft	\$ 6.68	\$ 9.19	\$ 4.52	\$ 7.26	\$ 9.04	\$ 8.38
Total Charges to BI 9603 (Incl. O/H)	\$ 615,440	\$ 608,068	\$ 758,920	\$ 1,046,217	\$ 691,824	\$ 831,648
Dollars Not Unitized	\$ 253,960	\$ (82,603)	\$ 257,781	\$ 137,969	\$ (6,668)	\$ (15,138)
2" or Less Ft Per Res. Customer	68	42	67	80	46	96
Unitized 2" or Less \$ Per Res Cust.	\$ 315	\$ 257	\$ 214	\$ 473	\$ 314	\$ 690
4" & 6" PE Ft. Per Total Cust.	30.2	21.5	11.4	24.2	22.0	20.4
4" & 6" PE Dollars Per Total Cust.	\$ 334	\$ 317	\$ 136	\$ 274	\$ 273	\$ 279
<u>Services (BI 9608)</u>						
< 2" PE Feet	39,335	104,749	41,437	58,862	54,391	67,574
< 2" PE Dollars	\$ 398,093	\$ 751,276	\$ 876,067	\$ 722,068	\$ 788,030	\$ 642,897
Dollars Per Ft	\$ 10.12	\$ 7.17	\$ 21.14	\$ 12.27	\$ 14.49	\$ 9.51
2" & Up PE & Steel Feet	2,974	218	718	1,065	429	1,350
2" PE & Up & Steel Dollars	\$ 5,557	\$ 2,400	\$ 46,778	\$ (10,490)	\$ 1,513	\$ 65,256
Total Service Footage (Unitized)	42,309	104,967	42,155	59,927	54,820	68,924
Total Service Dollars (Unitized)	\$ 403,649	\$ 753,676	\$ 922,845	\$ 711,579	\$ 789,543	\$ 708,153
Total Service Dollars Per Ft	\$ 9.54	\$ 7.18	\$ 21.89	\$ 11.87	\$ 14.40	\$ 10.27
Total Charges to BI 9608 (Incl. O/H)	\$ 406,229	\$ 928,874	\$ 928,874	\$ 787,071	\$ 794,854	\$ 713,503
<2" Ft Per Res. Customer	72	89	29	50	49	78
<2" Dollars Per Res Cust.	\$ 730	\$ 639	\$ 622	\$ 608	\$ 716	\$ 746

SOUTHWEST GAS CORPORATION

ARIZONA

DISTRICT 32 VALLEY
COST STATISTICS FOR NEW MAIN AND SERVICES
YEARS 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9

Size / Material	December 31, 2007			December 31, 2005			December 31, 2004			December 31, 2003			December 31, 2002		
	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.
< 2 Inch		\$													
2 Inch	58,376	23,724	0.41	453	689	1.52	289	\$	686	2.33	142	\$	3	217	72.33
2 Inch or less	58,376	23,724	0.41	162,610	1,024,247	6.30	201,444	1,321,316	6.56	114,005	672,941	5.90	68,383	586,869	8.58
Spec./Area/Submrgd Cross				163,063	1,024,936	6.29	201,743	1,322,011	6.55	114,147	673,806	5.90	68,386	587,086	8.58
4 Inch	17,280	206,444	11.95	72,127	612,577	8.49	26,936	279,265	10.37	44,685	305,184	6.83	406	201,194	495.55
6 Inch				72,127	612,577	8.49	26,936	279,265	10.37	44,685	305,184	6.83	36,047	319,613	8.87
> 2 Inch PE				72,127	612,577	8.49	26,936	279,265	10.37	44,685	305,184	6.83	36,047	319,613	8.87
< 2 Inch Steel				94	1,528										
2 Inch Steel	94	1,528		14,773	379,031					1	70	69.62	120	8,925	74.38
4 Inch Steel													342	17,314	50.63
6 Inch Steel													2	609	304.31
6+ Inch Steel													23,287	1,012,236	43.47
Total Mains	94	1,528	16.26	14,967	380,559	25.60	0	0	#DIV/0!	1	70	69.62	23,751	1,038,083	43.75
Ratio 4" & 6" PE as a % of 2"	75,750	231,686	3.06	250,057	2,018,072	8.07	228,679	1,601,277	7.00	158,833	979,060	6.16	128,590	2,146,977	16.70
Total Meter Sets	29,600			44,234			13,354			38,156			52,771		
Residential @ 98%	2,846			3,503			1,907			1,135			645		
2 Inch Pipe Per Meter Set	21			47			108			103			108		
Dollars Per Res. Mains 2"					289			707			606			929	
< 2 Inch															
2 Inch	276,447	1,088,889	3.98	77,879	1,241,077	15.94	101,827	868,800	8.51	31,844	694,758	21.82	66,521	678,764	10.20
2 Inch	276,447	1,088,889	3.98	77,879	1,241,077	15.94	101,827	868,800	8.51	31,844	694,758	21.82	66,521	678,764	10.20
4 Inch	1,489	12,531	8.36	8,647	56,326	6.51	1,326	17,611	13.28	1,293	22,901	17.71	2,195	66,794	31.80
4+ Inch													896	7,869	8.78
2 Inch or > PE	1,489	12,531	8.36	8,647	56,326	6.51	1,326	17,611	13.28	1,293	22,901	17.71	3,091	77,663	25.13
< 2 Inch Per Res. Meter Set															
Dollars Per Res. Service <2"	97	386		23	362		54	464		28	625		105	1,074	
< 2 Inch Steel															
2 Inch Steel															
6 Inch Steel															
Steel															
Total Services	0	0		88,526	1,297,403	14.99	103,153	884,412	8.57	33,436	749,990	22.43	742	89,291	
Total Footage Per Customer	277,946	1,111,430	4.00	142,740	1,898,754	13.29	174			169			308		

Standard Amounts Services		
<2" Dollars	\$	6,459,969
<2" Feet		697,011
<2" Cost Per	\$	9.27

Average Amounts 4/6" Mains		
2" Dollars	\$	2,240,530
2" Feet		241,243
2" Cost Per	\$	9.29

PE Mains		
Average Amounts 2" Mains		
2" Dollars	\$	6,046,401
2" Feet		987,375
2" Cost Per	\$	6.12
All Cust.		14,677
Res Ft Per		69
Cost Per Cust.		\$420

SOUTHWEST GAS CORPORATION

ARIZONA

DISTRICT 34 BULLHEAD CITY
COST STATISTICS FOR NEW MAIN AND SERVICES
YEARS 2002 THROUGH 2007

RESPONSE TO STAFF DATA REQUEST STF-5-9

Size / Material	December 31, 2007				December 31, 2008				December 31, 2009				December 31, 2010				December 31, 2011				December 31, 2012			
	Feet	Mains	Dollars	\$ Per Ft.	Feet	Mains	Dollars	\$ Per Ft.	Feet	Mains	Dollars	\$ Per Ft.	Feet	Mains	Dollars	\$ Per Ft.	Feet	Mains	Dollars	\$ Per Ft.	Feet	Mains	Dollars	\$ Per Ft.
< 2 Inch	1	9	\$	8.63	1	9	\$	8.63	5	12	\$	2.33	47,087	355,698	\$	7.55	136	5,252	\$	38.62	138	5,252	\$	38.62
2 Inch	18,399	343,196	\$	18.65	46,508	398,862	\$	8.57	64,117	471,410	\$	7.35	47,087	355,698	\$	7.55	31,388	324,862	\$	10.35	23,575	257,550	\$	10.92
2 Inch or less	18,400	343,204	\$	18.65	46,509	398,871	\$	8.57	64,122	471,422	\$	7.35	47,088	355,717	\$	7.55	31,524	330,105	\$	10.47	23,713	257,937	\$	10.88
Valve > 4 Inch			\$				\$				\$				\$				\$				\$	
4 Inch	7,331	368,763	\$		16,861	368,763	\$		10,035	168,177	\$		12,482	212,371	\$		5,296	61,010	\$	11.52	544	14,076	\$	25.87
6 Inch			\$		5,860	128,862	\$			88,011	\$		2,489	88,011	\$				\$				\$	
> 2 Inch PE	7,331	368,763	\$	50.44	22,821	498,715	\$	21.85	10,035	168,177	\$	16.76	14,971	300,383	\$	20.06	5,296	61,010	\$	11.52	544	14,076	\$	25.87
< 2 Inch Steel			\$				\$				\$				\$				\$				\$	
2 Inch Steel			\$				\$				\$				\$				\$				\$	
4 Inch Steel			\$				\$				\$				\$				\$				\$	
6 Inch Steel			\$				\$				\$				\$				\$				\$	
6+ Inch Steel			\$				\$				\$				\$				\$				\$	
Steel			\$				\$				\$				\$				\$				\$	
Total Mains	25,731	712,967	\$	27.71	69,330	887,385	\$	12.94	74,167	639,599	\$	8.62	62,059	656,100	\$	10.57	36,820	391,114	\$	10.62	24,257	272,013	\$	11.21
Ratio 4" & 6" PE as a % of 2"	39.84%				48.07%				15.65%				31.78%				16.80%				2.29%			
Total Meter Sels	608				1,274				1,553				1,128				732				521			
Residential @ 80%	602				1,261				1,537				1,117				725				521			
2 Inch Pipe Per Meter Set	31	570	\$		37	316	\$		42	307	\$		42	319	\$		44	456	\$		46	495	\$	
Dollars Per Res. Mains 2"			\$				\$				\$				\$				\$				\$	
Gas Lights			\$				\$				\$				\$				\$				\$	
< 2 Inch	46,202	80,073	\$	1.73	79,891	820,857	\$	10.30	91,267	1,153,192	\$	12.64	44,151	1,052,856	\$	23.85	116	2,787	\$	24.11	175	3,335	\$	19.06
Sleeving			\$				\$				\$				\$				\$				\$	
2 Inch W/O Trench	46,210	81,550	\$	1.76	79,899	822,334	\$	10.32	91,275	1,154,669	\$	12.65	44,234	1,057,338	\$	23.90	116	2,787	\$	24.11	175	3,335	\$	19.06
2 Inch	757	4,942	\$		581	7,767	\$		1,829	8,462	\$				\$		585	401	\$	0.89	592	3,272	\$	52.82
4+ Inch			\$				\$				\$				\$				\$				\$	
< 2 Inch or > PE	757	4,942	\$		581	7,767	\$		1,829	8,462	\$				\$		585	401	\$	0.89	592	3,272	\$	52.82
2 Inch Per Res. Meter Set			\$				\$				\$				\$				\$				\$	
Dollars Per Res. Service < 2"	77	135	\$		63	652	\$		59	751	\$		40	947	\$		63	815	\$		73	993	\$	
< 2 Inch Steel			\$				\$				\$				\$				\$				\$	
2 Inch Steel			\$				\$				\$				\$				\$				\$	
4 Inch Steel			\$				\$				\$				\$				\$				\$	
6 Inch Steel			\$				\$				\$				\$				\$				\$	
Steel			\$				\$				\$				\$				\$				\$	
Total Services	46,967	86,492	\$	1.84	80,280	830,101	\$	10.34	83,104	1,163,130	\$	12.49	44,234	1,057,338	\$	23.90	114	2,787	\$	24.11	175	3,335	\$	19.06
Total Footage Per Customer	120		\$		117		\$		108		\$		94		\$		94		\$		120		\$	

Standard Amounts Services			
< 2" Dollars	\$	4,223,331	
< 2" Feet	\$	345,419	
< 2" Cost Per	\$	12.23	
Res Cust.		5,763	
Res Ft Per		60	
Cost Per Cust.		\$733	

Average Amounts 4/6" Mains			
2" Dollars	\$	1,412,112	
2" Feet	\$	60,998	
2" Cost Per	\$	23.15	
All Cust.		5,821	
Res Ft Per		10	
Cost Per Cust.		\$243	

Average Amounts 2" Mains			
2" Dollars	\$	2,157,055	
2" Feet	\$	231,356	
2" Cost Per	\$	9.32	
Res Cust.		5,763	
Res Ft Per		40	
Cost Per Cust.		\$374	

**DISTRICT 36 TUCSON
COST STATISTICS FOR NEW MAIN AND SERVICES
YEARS 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-8**

rounded down to \$8.00

Standard Amounts Services	
<2" Dollars \$	27,005,409
<2" Feet	3,096,340
<2" Cost Per \$	8.72
Res Cust.	44,916
Res Ft Per	69
Cost Per Cust	\$601

Aver. Amounts 4/6" Mains	
4" 7/6" Dollars \$	5,856,549
4" 7/6" Feet	452,599
4" 7/6" Cost Per \$	12.94
All Cust.	46,305
Res Ft Per	10
Cost Per Cust	\$126

Units 2 nd Mains	PE Mains
\$ 16,263,458	22,120,007
2,253,108	2,705,707
\$ 7.22	8.18
44,916	
50	
8.22	

Average An	Res Cust.
2" Dollars	Res Fl Per
2" Feet	
2" Cost Per	

141125

Total Footage Per Customer

SOUTHWEST CORPORATION
ARIZONA

DISTRICT 42 PHOENIX
COST STATISTICS FOR NEW MAIN AND SERVICES
YEARS 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9

Size / Material	December 31, 2007			December 31, 2006			December 31, 2005			December 31, 2004			December 31, 2003			December 31, 2002		
	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.	Feet	Mains Dollars	\$ Per Ft.
< 2 Inch	986	\$ (638,441)	\$ (647.51)	1,059	\$ 105,557	\$ 99.68	3,433	\$ 576,161	\$ 167.83	2,386	\$ 1,033,889	\$ 433.31	1,531	\$ 105,243	\$ 68.74	850	\$ 59,094	\$ 69.52
2 Inch	892,056	\$ 11,003,105	\$ 12.47	1,476,471	\$ 16,113,260	\$ 10.91	1,341,864	\$ 12,455,683	\$ 9.28	1,840,958	\$ 14,696,109	\$ 8.96	1,895,582	\$ 15,318,240	\$ 9.03	1,384,627	\$ 14,663,595	\$ 10.59
2 Inch or less	883,042	\$ 10,364,684	\$ 11.74	1,476,530	\$ 16,218,817	\$ 10.98	1,345,297	\$ 12,455,683	\$ 9.28	1,840,958	\$ 14,696,109	\$ 8.96	1,895,582	\$ 15,318,240	\$ 9.03	1,384,627	\$ 14,663,595	\$ 10.59
Valve > 4 Inch	10	\$ 36,850	\$ 3,684.96	32	\$ 401,759	\$ 12,554.97	5	\$ 98,427	\$ 19,685.40	54	\$ 374,889	\$ 6,942.39	12	\$ 1,170,590	\$ 97,548.15	9	\$ 106,012	\$ 11,779.12
4 Inch	91,623	\$ 3,274,354	\$ 35.74	203,609	\$ 4,657,426	\$ 22.87	158,767	\$ 3,770,508	\$ 23.75	233,458	\$ 6,881,138	\$ 29.47	246,355	\$ 6,055,375	\$ 24.58	309,308	\$ 9,030,806	\$ 29.20
6 Inch	29,732	\$ 842,191	\$ 28.33	64,216	\$ 1,831,727	\$ 28.52	57,842	\$ 1,564,136	\$ 27.04	114,124	\$ 3,411,787	\$ 29.90	107,135	\$ 2,564,534	\$ 23.94	83,571	\$ 2,187,116	\$ 26.17
> 2 Inch PE	121,365	\$ 4,155,394	\$ 34.24	287,857	\$ 6,890,914	\$ 25.73	216,614	\$ 5,433,071	\$ 25.08	347,636	\$ 10,687,814	\$ 30.88	355,502	\$ 9,790,499	\$ 27.70	392,888	\$ 11,323,934	\$ 28.82
< 2 Inch Steel				189	\$ 679,809	\$ 3,596.87	189	\$ 679,809	\$ 3,596.87	25	\$ 207,117	\$ 8,264.68	26	\$ 18,721	\$ 720.05	99	\$ 12,503	\$ 126.29
2 Inch Steel	67	\$ 275,766	\$ 4,115.91	233	\$ 303,962	\$ 1,304.56	244	\$ 1,278,249	\$ 5,238.73	525	\$ 283,931	\$ 540.82	184	\$ 513,267	\$ 2,789.49	1,058	\$ 159,044	\$ 150.61
4 Inch Steel	331	\$ 129,979	\$ 392.69	637	\$ 426,584	\$ 669.68	1,906	\$ 65,151	\$ 40.57	1,368	\$ 1,008,366	\$ 737.11	1,887	\$ 396,980	\$ 210.38	12,408	\$ 373,099	\$ 30.07
6 Inch Steel	7,239	\$ 1,431,336	\$ 197.73	7,239	\$ 1,431,336	\$ 197.73	12,436	\$ 619,468	\$ 49.81	11,350	\$ 275,578	\$ 24.28	7,064	\$ 665,903	\$ 94.27	24,273	\$ 929,012	\$ 38.27
8 Inch Steel	8	\$ 1,819	\$ 227.38						#DIV/0!	30,761	\$ 1,382,803	\$ 44.95	39,163	\$ 1,311,041	\$ 33.48	34,341	\$ 81,837	\$ 239.99
8-10 Inch Steel	18	\$ 35,586	\$ 1,977.00	12	\$ 5,681	\$ 473.41	4	\$ 424	\$ 108.01	22,580	\$ 1,918,535	\$ 84.97	19	\$ 29,293	\$ 1,541.72	40	\$ 3,530	\$ 88.26
Steel	7,683	\$ 1,874,486	\$ 244.62	8,121	\$ 2,167,563	\$ 266.91	14,479	\$ 2,543,101	\$ 182.58	66,609	\$ 5,076,329	\$ 76.21	48,343	\$ 2,935,205	\$ 60.72	38,217	\$ 1,559,025	\$ 40.79
Total Mains	1,012,070	\$ 16,394,544	\$ 16.20	1,753,508	\$ 25,277,294	\$ 14.42	1,576,390	\$ 21,108,016	\$ 13.39	2,057,989	\$ 31,474,141	\$ 15.30	2,098,958	\$ 28,149,187	\$ 13.41	1,816,562	\$ 27,665,646	\$ 15.20
Ratio 4" & 6" PE as a % of 2"	13.74%			18.13%			16.10%			21.15%			20.83%			28.36%		
Meter Sets Thru Dec.	20,446			28,456			29,051			29,858			26,583			23,987		
Residential @ 98%	20,037			25,930			28,470			29,261			26,051			23,267		
2 Inch Pipe Per Meter Set	44			57			47			58			65			80		
Dollars Per Res. Mains 2"	\$ 517			\$ 625			\$ 458			\$ 538			\$ 592			\$ 633		
< 2 Inch	1,110,523	\$ 12,737,724	\$ 11.47	850,442	\$ 15,518,995	\$ 18.25	939,278	\$ 12,249,491	\$ 13.04	1,427,334	\$ 13,384,902	\$ 9.38	1,320,266	\$ 12,980,819	\$ 9.83	1,089,864	\$ 10,154,595	\$ 9.32
< 2 Inch	1,110,523	\$ 12,737,724	\$ 11.47	850,442	\$ 15,518,995	\$ 18.25	939,278	\$ 12,249,491	\$ 13.04	1,427,334	\$ 13,384,902	\$ 9.38	1,320,266	\$ 12,980,819	\$ 9.83	1,089,864	\$ 10,154,595	\$ 9.32
2 Inch	105,187	\$ 2,474,139	\$ 23.52	62,252	\$ 2,529,125	\$ 40.63	78,086	\$ 1,584,330	\$ 21.70	119,763	\$ 2,122,247	\$ 17.72	157,866	\$ 3,000,583	\$ 19.01	155,842	\$ 7,067,059	\$ 45.35
4 Inch			#DIV/0!	11,857	\$ 982,438	\$ 81.17	3,198	\$ 135,159	\$ 42.26	3,588	\$ 134,619	\$ 37.52	1,088	\$ 177,205	\$ 161.39	9,391	\$ 250,988	\$ 26.73
4-6 Inch				74,109	\$ 3,491,563	\$ 47.11	81,284	\$ 1,829,489	\$ 22.51	123,351	\$ 2,256,866	\$ 18.30	158,964	\$ 3,177,788	\$ 19.99	167,027	\$ 7,346,046	\$ 43.98
2 Inch or > PE	105,187	\$ 2,474,139	\$ 23.52															
< 2 Inch Per Res. Meter Set	55			33			33			49			51			47		
Dollars Per Res. Service<2"	\$ 636			\$ 588			\$ 430			\$ 457			\$ 498			\$ 436		
< 2 Inch Steel				54	\$ 180	\$	28	\$ 2,317	\$	2	\$ 328	\$	128	\$ 9,219	\$ 72.03	18	\$ 1,159	\$ 64.37
2 Inch Steel			#DIV/0!				5	\$ 455	\$ 91.00	53	\$ 3,017	\$ 56.93	92	\$ 3,495	\$ 37.99	90	\$ 9,562	\$ 106.25
4 Inch Steel			#DIV/0!	48	\$ 9,851	\$ 205.44	1,055	\$ 115,277	\$ 109.27	112	\$ 17,505	\$ 156.29	127	\$ 34,195	\$ 269.25	984	\$ 67,230	\$ 67.64
6 Inch Steel				60	\$ 10,328											14	\$ 1,017	\$ 72.63
8 Inch Steel				162	\$ 20,369	\$ 125.73	1,088	\$ 118,049	\$ 108.50	167	\$ 20,848	\$ 124.84	347	\$ 46,909	\$ 135.19	1,116	\$ 78,968	\$ 70.76
Steel	1,215,710	\$ 15,211,863	\$ 12.51	924,713	\$ 19,030,927	\$ 20.58	1,021,650	\$ 14,197,029	\$ 13.90	1,550,852	\$ 15,662,616	\$ 10.10	1,479,607	\$ 16,205,516	\$ 10.95	1,256,007	\$ 17,578,908	\$ 13.97
Total Services	109			101			89			121			135			128		
Total Footage Per Customer																		

Standard Amounts Services		
<2" Dollars	\$ 77,026,526	
<2" Feet	6,737,737	
<2" Cost Per \$	11.43	

Average Amounts 4/6" Mains		
4/6" Dollars	\$ 48,261,628	
4/6" Feet	1,689,862	
4/6" Cost Per \$	28.39	

Average Amounts 2" Mains		
2" Dollars	\$ 85,491,494	
2" Feet	8,431,803	
2" Cost Per \$	10.14	

PE Mains		
133,753,121		
10,131,665		
13.20		

Res. Cust.		
Res Ft Per	55	
Cost Per Cust.	\$559	

All Cust.		
Res Ft Per	156,384	
Cost Per Cust.	\$309	

SOUTHWEST ARIZONA CORPORATION

**DISTRICT 47 SOUTHEAST
COST STATISTICS FOR NEW MAIN AND SERVICES
YEARS 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9**

Size / Material	December 31, 2007				December 31, 2008				December 31, 2009				December 31, 2010				December 31, 2011			
	Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.	
< 2 Inch	65	\$ 1,158	\$ 17.82		59	\$ 184	\$ 3.12		51	\$ 218	\$ 4.27		1,297	\$ 10,818	\$ 8.34		808	\$ 11,805	\$ 14.61	
2 Inch	20,804	\$ 189,194	\$ 8.13		67,186	\$ 307,205	\$ 5.91		40,640	\$ 320,211	\$ 7.88		50,791	\$ 308,563	\$ 6.08		49,955	\$ 274,151	\$ 5.49	
2 Inch or less	20,869	\$ 170,352	\$ 8.16		67,245	\$ 397,369	\$ 5.91		40,691	\$ 320,429	\$ 7.87		50,763	\$ 285,956	\$ 5.63		49,678	\$ 380,384	\$ 6.37	
Valve > 4 Inch																				
4 Inch	20,447	\$ 203,967	\$ 9.98		18,530	\$ 188,794	\$ 10.19		14,395	\$ 150,418	\$ 10.45		10,812	\$ 90,454	\$ 8.37		4,130	\$ 56,367	\$ 14.13	
6 Inch																				
> 2 Inch PE	20,447	\$ 203,967	\$ 9.98		18,530	\$ 188,794	\$ 10.19		14,395	\$ 150,418	\$ 10.45		10,812	\$ 90,454	\$ 8.37		4,130	\$ 56,367	\$ 14.13	
< 2 Inch Steel																				
2 Inch Steel																				
4 Inch Steel																				
6 Inch Steel																				
8 Inch Steel																				
6+ Inch Steel																				
Total Mains	0	\$ 0	\$ 0.00		0	\$ 0	\$ 0.00		41,976	\$ 8,926	\$ 0.21		1,806	\$ 72,552	\$ 40.17		1,807	\$ 72,596	\$ 40.17	
Ratio 4" & 6" PE as a % of 2"	41,316	\$ 374,319	\$ 9.06		65,775	\$ 586,183	\$ 8.93		97,082	\$ 479,773	\$ 4.94		62,900	\$ 409,835	\$ 6.52		56,700	\$ 415,919	\$ 7.35	
Meter Sets Thru Dec	97,986				27,586				35,386				20,766				8,146			
Residential @ 93%	622				871				881				964				753			
2 Inch Pipe Per Meter Set	578				810				807				887				700			
Dollars Per Res. Mains 2"	36	\$ 294			83	\$ 491			50	\$ 391			59	\$ 360			72	\$ 408		
New Services																				
< 2 Inch	66,015	\$ 375,045	\$ 5.68		64,178	\$ 548,178	\$ 8.54		44,657	\$ 571,249	\$ 12.78		67,574	\$ 576,381	\$ 8.53		69,268	\$ 474,916	\$ 6.85	
2 Inch	66,015	\$ 375,045	\$ 5.68		64,178	\$ 548,178	\$ 8.54		44,657	\$ 571,249	\$ 12.78		67,574	\$ 576,381	\$ 8.53		69,268	\$ 474,916	\$ 6.85	
2 Inch or > PE	10	\$ 219	\$ 21.88		663	\$ 3,898	\$ 5.88		2,075	\$ 29,592	\$ 14.28		3,222	\$ 35,346	\$ 10.97		13	\$ 1,385	\$ 108.55	
< 2 Inch Per Res. Meter Set	10	\$ 219	\$ 21.88		663	\$ 3,898	\$ 5.88		2,075	\$ 29,592	\$ 14.28		3,222	\$ 35,346	\$ 10.97		13	\$ 1,385	\$ 108.55	
Dollars Per Res. Service < 2"	114	\$ 648			79	\$ 677			55	\$ 697			76	\$ 650			99	\$ 678		
< 2 Inch Steel	161	\$ 4,703	\$ 29.21		430	\$ 4,703	\$ 10.94		878	\$ 13,508	\$ 15.38		26	\$ 1,180	\$ 45.40		1,070	\$ 12,096	\$ 11.30	
2 Inch Steel	10	\$ 219	\$ 21.88		225	\$ 2,345	\$ 10.45		26	\$ 1,180	\$ 45.40		26	\$ 1,180	\$ 45.40		1,070	\$ 12,096	\$ 11.30	
4 Inch Steel					1,164	\$ 32,907	\$ 28.27		1,179	\$ 41,673	\$ 35.35		44	\$ 4,904	\$ 111.45		924	\$ 27,137	\$ 29.37	
6 Inch Steel																				
Total Services	171	\$ 4,922	\$ 5.74		1,819	\$ 39,955	\$ 22.00		2,057	\$ 55,181	\$ 27.28		70	\$ 6,084	\$ 86.91		3,236	\$ 53,651	\$ 16.58	
Total Footage Per Customer	66,196	\$ 380,186	\$ 5.74		66,060	\$ 592,031	\$ 8.88		48,789	\$ 656,022	\$ 13.45		70,866	\$ 617,811	\$ 8.72		72,517	\$ 529,952	\$ 7.31	
	173				175				186				140				172			

Standard Amounts Services		
< 2" Dollars	\$	3,032,410
< 2" Feet		377,854
< 2" Cost Per	\$	8.03

Average Amounts 4/8" Mains		
2" Dollars	\$	748,307
2" Feet		74,077
2" Cost Per	\$	10.10

Average Amounts 2" Mains		
2" Dollars	\$	1,873,891
2" Feet		291,334
2" Cost Per	\$	6.43

Average Amounts 2" Mains		
2" Dollars	\$	1,873,891
2" Feet		291,334
2" Cost Per	\$	6.43

Average Amounts 2" Mains		
2" Dollars	\$	1,873,891
2" Feet		291,334
2" Cost Per	\$	6.43

Average Amounts 2" Mains		
2" Dollars	\$	1,873,891
2" Feet		291,334
2" Cost Per	\$	6.43

Average Amounts 2" Mains		
2" Dollars	\$	1,873,891
2" Feet		291,334
2" Cost Per	\$	6.43

Average Amounts 2" Mains		
2" Dollars	\$	1,873,891
2" Feet		291,334
2" Cost Per	\$	6.43

SOUTHWEST CORPORATION
ALBUQUERQUE, NM

DISTRICT 48 YUMA
COST STATISTICS FOR NEW MAIN AND SERVICES
YEARS 2002 THROUGH 2007
RESPONSE TO STAFF DATA REQUEST STF-5-9

Size / Material	December 31, 2007				December 31, 2008				December 31, 2009				December 31, 2010				December 31, 2011				December 31, 2012			
	Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.		Feet	Mains Dollars	Per Ft.	
< 2 Inch	17	\$ 102	\$		14	\$ 76	\$		20	\$ 12	\$		30	\$ 32	\$		1	\$ 8	\$		1	\$ 8	\$	
2 Inch	36,976	\$ 171,899	4.65		48,829	\$ 302,126	6.19		95,005	\$ 561,930	5.91		51,096	\$ 345,349	6.76		82,864	\$ 595,058	7.20		82,864	\$ 595,058	7.20	
2 Inch or less	36,993	\$ 172,001	4.65		48,843	\$ 302,202	6.19		95,025	\$ 561,943	5.91		51,126	\$ 345,382	6.76		82,865	\$ 595,067	7.20		82,865	\$ 595,067	7.20	
Valve > 4 Inch									86	\$ 2,818	\$		409	\$ 11,029	\$									
4 Inch	17,128	\$ 189,479	11.06		26,305	\$ 388,469	14.77		29,953	\$ 338,661	11.31		25,224	\$ 313,132	12.41		18,328	\$ 250,954	13.69		18,328	\$ 250,954	13.69	
6 Inch																								
> 2 Inch PE	17,128	\$ 189,479	11.06		26,305	\$ 388,469	14.77		29,953	\$ 338,661	11.31		25,224	\$ 313,132	12.41		18,328	\$ 250,954	13.69		18,328	\$ 250,954	13.69	
< 2 Inch Steel									28	\$ 305	\$		21	\$ 1,354	\$		0	\$ 0	\$		0	\$ 0	\$	
2 Inch Steel									69	\$ 1,483	\$		478	\$ 27,596	57.73		20	\$ 765	38.23		20	\$ 765	38.23	
4 Inch Steel																								
6 Inch Steel																								
8 Inch Steel																								
Total Mains	54,121	\$ 361,480	6.68		75,148	\$ 690,671	9.19		110,806	\$ 501,139	4.52		125,161	\$ 908,248	7.26		49,343	\$ 28,950	58.02		49,343	\$ 28,950	58.02	
Ratio 4" & 6" PE as a % of 2"	46.30%				53.66%				17.81%				31.52%				49.34%				49.34%			
Meter Sets Thru Dec	568				1,225				1,488				1,237				1,147				898			
Residential @ 96%	545				1,176				1,408				1,101				862				862			
2 Inch Pipe Per Meter Set	68				42				67				80				46				96			
Dollars Per Res. Mains 2"		\$ 315				\$ 257				\$ 214				\$ 473				\$ 314				\$ 690		
New Services	39,335	\$ 398,093	10.12		104,749	\$ 751,276	7.17		41,437	\$ 876,067	21.14		58,862	\$ 722,068	12.27		54,391	\$ 788,030	14.49		54,391	\$ 788,030	14.49	
< 2 Inch	39,335	\$ 398,093	10.12		104,749	\$ 751,276	7.17		41,437	\$ 876,067	21.14		58,862	\$ 722,068	12.27		54,391	\$ 788,030	14.49		54,391	\$ 788,030	14.49	
2 Inch	2,972	\$ 4,524	1.52		216	\$ 1,367	6.33		704	\$ 45,873	65.16		1,065	\$ (10,490)	(9.85)		413	\$ (1,725)	(4.18)		413	\$ (1,725)	(4.18)	
4 Inch																								
42 Inch																								
2 Inch or > PE	2,972	\$ 4,524	1.52		216	\$ 1,367	6.33		704	\$ 45,873	65.16		1,065	\$ (10,490)	(9.85)		413	\$ (1,725)	(4.18)		413	\$ (1,725)	(4.18)	
< 2 Inch Per Res. Meter Set																								
Dollars Per Res. Service-2"	72	\$ 730			89	\$ 639			28	\$ 622			50	\$ 608			49	\$ 716			49	\$ 716		
< 2 Inch Steel																								
2 Inch Steel	2	\$ 1,033	\$		2	\$ 1,033	\$		14	\$ 905	\$			\$	\$		16	\$ 3,238	\$		16	\$ 3,238	\$	
4 Inch Steel																								
6 Inch Steel																								
Steel	2	\$ 1,033	\$		2	\$ 1,033	\$		14	\$ 905	\$			\$	\$		16	\$ 3,238	\$		16	\$ 3,238	\$	
Total Services	42,309	\$ 403,649	9.54		104,967	\$ 753,676	7.18		42,155	\$ 922,845	21.89		59,927	\$ 711,579	11.87		54,820	\$ 789,543	14.40		54,820	\$ 789,543	14.40	
Total Footage Per Customer	170				147				104				150				115				115			

Standard Amounts Services	
< 2" Dollars	\$ 4,178,430
< 2" Feet	368,348
< 2" Cost Per \$	11.41

Aver. Amounts 4/6" Mains	
2" Dollars	\$ 1,680,764
2" Feet	133,693
2" Cost Per \$	12.57

PE Mains	
2" Dollars	\$ 3,958,448
2" Feet	542,366
2" Cost Per \$	7.30

Aver. Amounts 2" Mains	
2" Dollars	\$ 2,277,683
2" Feet	408,703
2" Cost Per \$	5.57

Res Cust.	5,419
Res Ft Per	68
Cost Per Cust.	\$771

241-068

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

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**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-68:

Internal Audits. Please list all internal audit reports of SWG and its affiliates for 2005 through 2007. Please make copies of the listed internal audit reports available for review. Also, provide a list of all internal audits currently being undertaken for which a report has not yet been issued.

Respondent: Internal Audit

Response:

Please see the attached lists.

Attachment A provides a list of all internal audit reports of Southwest and its affiliates from 8/1/04 through 11/1/07.

Attachment B provides a list of all internal audits in progress.

Southwest deems the contents of the internal audit reports "confidential" and will provide copies of selected reports or make them available for review on-site subject to a signed protective agreement between Southwest and ACC Staff.

Attachment A:
Internal Audit Reports Issued
August 15, 2004 - November 15, 2007

Audit Report Title	Report Date
Elko District Audit	8/15/04
Winnemucca District Audit	8/16/04
Mobile Service Application Review	8/24/04
Help Desk/Remedy Review	8/25/04
Corporate Purchasing Audit	8/30/04
Electronic Mapping Repository System Application Review	8/31/04
Shareholder Relations System Application Review	9/9/04
SOX General Computer Controls (A&P)	9/20/04
SOX NPL Review	9/21/04
Carson City District Audit	9/24/04
Physical Inventory	10/5/04
Oracle Security Review	10/25/04
LNG Inventory Allocation Audit	11/17/04
LNG Inventory Allocation Audit Report for Year-End 2004/Gruber	11/18/04
LNG Inventory Allocation Audit Report for Year-End 2004/Armstrong	11/18/04
WMDVBE Validation Review	12/28/04
UNIX Security Review	1/4/05
CICS/VTAM Review	3/21/05
SAP Post-Implementation Review	3/25/05
Ernst & Young's SAP Post-Implementation Review	3/25/05
Customer Assistance Support & Training Audit	4/7/05
SWG Foundation 2004 Financial Statements	4/15/05
Product Evaluation	5/12/05
TSO and SDSF System Software Reviews	5/20/05
Wireless Security Review	5/24/05
Cisco Router Security Review	6/10/05
Yuma District Audit	6/16/05
Treasury Services Department Audit	6/16/05
Accounts Payable Audit	6/16/05
Right of Way Department Audit	6/21/05
NPL - Manassas Operations Audit	7/15/05
Annual Physical Inventory	8/19/05
Corporate Communications & Community Affairs	8/29/05
Contract Administration	9/13/05
Help Desk Review	9/16/05
Southwest Vista Review	9/22/05
Training Tracking System Application Review	9/26/05
NPL Illinois Operations & Limited SOX Audit	9/26/05
NPL Lakeville, MN - Operations Audit	10/11/05
Incline Truckee District Audit	10/11/05
OpenVMS Operating System & SCADA System Reviews - Corporate	10/11/05

Internal Audit Reports Issued **August 15, 2004 - November 15, 2007**

Audit Report Title	Report Date
OpenVMS Operating System & SCADA System Reviews - Paiute	10/24/05
Information Management System Database Review	10/24/05
GroupWise Application Review	10/24/05
Gas Purchases & Transportation Operational Audit	10/24/05
NPL Phoenix Fraud Investigation	10/25/05
Mobile Services Review	10/26/05
KoVIS Review	10/26/05
Software Plus Review	10/28/05
LNG Inventory Allocation Audit	11/17/05
LNG Inventory Allocation Audit Report for YE 2005 - Sierra Pacific	11/17/05
LNG Inventory Allocation Audit Report for YE 2005 - SWG	11/17/05
Data Center Review	11/28/05
Credit & Collections Function Operational Audit	11/28/05
Data Center Access Review	12/6/05
Oracle Application Parameter Review	12/6/05
General Computer Control Reviews	12/6/05
GCC - Novell Quarterly Review	12/9/05
DRMS	12/16/05
Europe	12/21/05
Fallon Audit Report	1/4/06
Aviation Final Report	1/6/06
NPL Baltimore	1/6/06
Electronic Mapping Repository System	1/16/06
Tucson District	1/17/06
NPL Tucson Audit Report	1/19/06
Vista Plus	1/27/06
Meter Tracking System	2/10/06
Oracle Discover System	2/13/06
Corporate Policies & Procedures Audit	2/15/06
CAP & Billing Control Audit	2/15/06
Employee Retirement Plan Recalculation Audit	2/15/06
Reconciliation System (RCN) Application Review	2/15/06
GroupWise Application Review	2/16/06
Phoenix District Audit	2/17/06
NPL Prescott Valley Operations & Limited SOX Audit	2/21/06
NPL Tucson, AZ SOX & Operations Audit	2/24/06
Bullhead City District Audit	3/2/06
Las Vegas District Audit	3/15/06
Telecommunication Review	3/16/06
Mobile Services	3/20/06
Cisco Router Security Review	3/21/06
Shareholder Relations System Review	3/23/06
Corporate Fleet Management Audit	3/27/06

Internal Audit Reports Issued August 15, 2004 - November 15, 2007

Audit Report Title	Report Date
Fleet Information System Review	3/31/06
HR Compensation Audit - 5 day	4/11/06
RACF Security Review	4/14/06
HR Compensation	4/19/06
Physical Access	4/24/06
Work Management System (WMS) Application Review	5/10/06
Bank of America Direct System	5/16/06
Data Request Management System Review	5/17/06
GTS Review	5/18/06
Facilities Management (Building Services Dept) Audit	5/19/06
Engineering Staff - Code Compliance	6/1/06
Carson City District Audit	6/12/06
UNIX Security Review	6/13/06
Sierra Vista & Douglas Offices/Southeast Arizona District Audit	6/14/06
Hiring Practices Audit	6/14/06
Morenci Office/Eastern Arizona District Audit	6/19/06
Sarbanes-Oxley Logical Security Control B8.8	6/19/06
ITRON Premiere Plus 4 Review	6/28/06
Operational Quality Assurance Department Audit	6/28/06
Materials Management Information Systems (MMIS) Review	7/5/06
Sierra Vista & Douglas Offices/Southeast Arizona District Audit	7/14/06
Issue from PWC's Interim ITGC Testing	7/14/06
Oracle Discoverer System Review	7/14/06
Risk Management Audit	7/24/06
Corporate Purchasing	8/8/06
NPL Dallas Operations & Limited Sox Audit	8/21/06
Sarbanes-Oxley Logical Security Control	8/21/06
Engineering Staff - Design & Standards	8/21/06
KoVIS	8/30/06
Paiute SCADA	9/14/06
Attack and Penetration External Security Review	9/15/06
Measurement & Control (Eng. Staff)	9/19/06
Employee Expense Report	9/21/06
Victorville District	9/29/06
SCADA - Paiute	9/29/06
GRPS	10/4/06
PI Report	10/6/06
Equity Edge	10/30/06
TSO and SDSF	10/30/06
Sarbanes-Oxley Logical Network Control	10/31/06
Corporate Compliance	11/15/06

Internal Audit Reports Issued August 15, 2004 - November 15, 2007

Audit Report Title	Report Date
Paiute Pipeline Liquefied Natural Gas Inventory Allocation Audit	11/16/06
Continuing Property Records Application Review	11/20/06
Walker General Ledger Application Review	11/20/06
Plant Information	11/27/06
Work Order System Report	11/27/06
NPL Kansas Audit Report	11/29/06
Novell Security	11/30/06
Hedge Capture & Control	12/18/06
WMS Audit Report	12/20/06
Corporate Payroll	12/20/06
Globe District Audit	12/20/06
NPL Connecticut	12/26/06
GOSS Construction	12/29/06
GOSS Contractor Qualification	12/29/06
Line Locate / Leak Survey Review	12/29/06
NPL Colorado	12/29/06
Equal Employment / Affirmative Action	1/4/07
Oracle Review	1/8/07
Help Desk Review	1/8/07
Big Bear District Audit	1/22/07
Citrix Review	1/24/07
Vista Plus Application Review	1/31/07
Aviation Audit	2/8/07
Inventory Management Review	2/9/07
Valley District/Southern AZ Division	2/20/07
NPL Minden, NV Operations & SOX	2/27/07
Accounting Control Review	2/27/07
Paiute Pipeline Scheduling System	3/7/07
Training Tracking System (TTS) Application Review	3/9/07
Equity Edge Application Review	3/19/07
Workers' Compensation Audit	3/20/07
Corporate HR Training	3/20/07
Cisco Router Review	3/23/07
Affiliate Transactions	4/3/07
SWG Foundation Review	4/5/07
Electronic Mapping Repository System (EMRS)	4/6/07
GroupWise Application Review	4/13/07
Resource Access Control Facility (RACF)	5/1/07
Credit & Collections Audit	5/14/07
Paiute Open VMS, Operating System & SCADA	5/15/07
SWG Open VMS, Operating System & SCADA	5/15/07
Voice Communications Review	5/17/07
Transfer Agent/Registrar Review	5/29/07
Southwest Vista Review	5/29/07
Data Center Review	6/1/07
Elko District Audit	6/5/07

**Internal Audit Reports Issued
August 15, 2004 - November 15, 2007**

Audit Report Title	Report Date
Winnemucca District Audit	6/5/07
South Lake Tahoe District Office/Northern NV Division	6/5/07
NPL Georgia Area Office & SOX	6/8/07
Yuma District Audit	6/12/07
Mobile Service Application Review	6/19/07
Key Account Management Review	6/27/07
Disk Management Review	7/9/07
Pricing & Tariffs Audit	7/9/07
Systems Planning Audit	7/9/07
ITRON Premiere Plus 4 System Review	7/17/07
Information Management System Database (IMS)	7/17/07
Paiute Pipeline Scheduling System	7/18/07
Contract Administration Department	7/24/07
NPL Special Projects Office	8/8/07
Central Graphics Review	8/8/07
Novell Security (eDirectory)	8/9/07
Oracle Database Review	8/10/07
Incline Village/Truckee District	8/17/07
Work Management System (WMS) Application	8/23/07
Citrix Review	8/27/07
Employee Expense Reports	8/29/07
Time Sharing Option System Display/Search Facility	9/7/07
NPL Las Vegas Operations & SOX	9/24/07
NPL PG County, MD Operations & SOX	9/24/07
Revenue Requirements Review	9/25/07
Oracle Discoverer System	9/28/07
UNIX Security Review	10/2/07
Dial-In Access Review	10/2/07
Annual Physical Inventory	10/31/07
Materials Management Information Systems (MMIS) Review	11/13/07

**Attachment B:
Internal Audits In Progress
as of November 15, 2007**

Audit Description	Expected Completion Date
Audits of Internal Controls Over Financial Reporting	
Revenue Cycle	12/28/2007
Tax Cycle	12/28/2007
Procure-to-Pay Cycle	12/28/2007
Treasury Cycle	12/28/2007
Payroll & Benefits Cycle	12/28/2007
Property Cycle	12/28/2007
Gas and Regulatory Accounting Cycle	12/28/2007
Entity Level Controls	12/28/2007
Financial Reporting Cycle	12/28/2007
Critical Spreadsheets	12/28/2007
NPL Central	12/28/2007
NPL Entity Level Controls	12/28/2007
NPL Critical Spreadsheets	12/28/2007
Operational Audits	
Employee Health Insurance Audit	12/28/2007
Corporate Safety Audit	12/28/2007
Federal Regulatory Affairs	12/28/2007
State Regulatory Affairs	12/28/2007
NPL Ontario Area Office	11/30/2007
NPL Phoenix Area Office	11/30/2007
GEDAC Audit	11/30/2007
Information Technology Audits	
SOX General Computing Control Review	12/28/2007
NPL - SOX General Computing Control Review	12/28/2007
Employee Accounts Receivables System Review	11/1/2007
Kofile Visual Information System Review	11/15/2007
Help Desk / Remedy Application Review	11/15/2007
Risk Master System Review	11/30/2007
SOX Financial Cycle Automated Controls	12/28/2007

241-073

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-73:

Management Audits. Please provide a copy of any and all management and performance audits of the Company, issued since the last rate case.

Respondent: Internal Audit

Response:

Please see the list of internal audit reports provided in response to data request no. STF-1-68.

All significant functions, activities, and systems of the Company are subject to an internal audit, including functions performed by management. Internal Audit takes a risk-based approach to selecting which audits to perform. The audit plan is reviewed with and approved by the Audit Committee of the Southwest Board of Directors each year.

Southwest deems the contents of the internal audit reports "confidential" and will provide copies of selected reports or make them available for review on-site subject to a signed protective agreement between Southwest and ACC Staff.

241-035

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

* * *

**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-35:

Cost-saving Programs. Please list and describe in detail any cost-saving programs implemented during the period 2006 through the present. For each program listed in response to this request, show the anticipated and achieved savings. Include calculations of savings amounts and explain any assumptions used in such calculations. For each cost-saving program listed, provide the cost-benefit analyses for each program. Show the impact of each such cost-saving program on the test year.

Respondent: Revenue Requirements / Divisions

Response:

1. In March 2007, Construction adopted a program that allows Line Locators to receive work tickets via PC. The program allows for a centralized printer to print all tickets, reducing the need to sort tickets that previously came in via fax. Consequently, the fax machine is no longer needed; therefore, eliminating the need to renew the lease. Savings in manpower are estimated at 1-2 hours a week per yard.
2. In 2007, Construction -- West assigned a third welder to the fabrication shop at the 43rd Avenue facility. This assignment has allowed the shop to produce all needed spools, Meter Set Assemblies, regulator stations and various other fabrications while greatly reducing overtime. In addition to the reduction in overtime, fabrications made by contractors have also been greatly reduced (zero since the third welder was added). Estimated savings include 6-8 overtime hours per week, a reduction in invoicing from contractors and this also allows Mt. View personnel to use its weld shop space for other needs.

(Continued on Page 2)

Response to STF-1-35: (continued)

3. In 2007, Customer Service adopted a new technician truck design to decrease overall operating costs. The savings equates to approximately \$3,500 per vehicle. In 2007, 40 trucks were replaced and 23 modified for a total of 63 trucks; 11 vehicles will be replaced in 2008. The cost savings for both years will be \$295,000.
4. From May to October of 2007, Construction -- West adjusted the shift reporting time for one hit truck to 5:30 a.m. This change was in response to the high number of line breaks that occur early in the morning in the Festival Ranch area. Festival Ranch is located midway between the Wickenburg and 43rd Avenue facilities, making response to emergencies during rush hour difficult. By deploying this crew early, response time was reduced considerably and the need for a call-out of duty crews was negated. During this six-month span, crews responded to approximately 10 emergency calls, which saved an estimated 60 hours of overtime.

241-036

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

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**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-36:

Cost-saving Programs. Please provide a complete explanation of any and all expense reduction goals the Company has concerning the development of its 2007 and 2008 budgets.

Respondent: Corporate Planning Department

Response:

The Company did not have any specific expense reduction goals during the preparation of the 2007 and 2008 budgets. The Company budget is prepared utilizing a bottom-up approach, in which all Divisions and Staff Departments are provided targets for capital expenditures and operations and maintenance ("O&M") expenses for use during preparation of their respective budgets. The Division/Department budgets are approved by the Vice President responsible for that function.

These individual budgets are compiled by the Corporate Planning Department, analyzed for reasonableness, and presented to senior management for approval. If senior management questions the amount of any particular capital or O&M item, additional research is performed by the Corporate Planning Department and the applicable Division or Staff Department. The results of this additional research are then presented to senior management; if the expenditure is not deemed necessary, the item is removed from the budget.

Management Audit of the
Maryland Natural Gas Division
of the
Washington Gas Light Company

For the
Maryland Public Service Commission

April 1990

Theodore Barry &- Associates
A TB&A/Group Company

Los Angeles' Atlanta' Chicago' New York' Wellesley

Executive Summary

This chapter discusses the frame of reference of the audit, provides TB&A's overall assessment of the company, and presents the recommendations for each of the four focus areas in priority ranking. It also includes our overall recommendations for the company and the Commission with respect to the major issues facing the company in the Nineties.

Context of the Audit

When reviewing the findings, conclusions and recommendations of this audit and forming overall judgements about Maryland Natural Gas and Washington Gas Light Company, it is important to keep in mind the overall context of this report. As explained in the introduction, this study was a focused audit of four specific functional areas of the company. While three of those areas, organization, planning and work management transcend specific functional areas and affect the entire company, the reader must bear in mind that major areas of the company's operations, such as gas supply, gas operations, finance and accounting, and information systems, to name a few, were outside the scope of the audit. Some of those areas, particularly gas supply, have been examined in other recent audits for the Commission; TB&A reviewed their conclusions but did not duplicate those studies. As a result, overall conclusions about the company's management and operations must be considered carefully against the backdrop of this and the other studies.

Overall Conclusions

With those caveats, the crossfunctional nature of most of the areas audited enabled us to form some overall conclusions about the company. Overall, we believe the company is reasonably well-managed. Management has demonstrated a commitment to shape the organization to meet the needs of the various stakeholders, a "form follows function" orientation. We recommend improvements to the company's planning and goal-setting process, but note that the most difficult part of that process, that of developing a goal-setting orientation and implementing a process, is already in place and has the commitment of all levels of management. This is reflected in our recommendations in the area of corporate and strategic planning, which are more in the nature of fine-tuning as opposed to revamping.

In the areas of customer services and personnel, labor relations and work management, the company has also demonstrated a commitment to improvement. The 1985 reorganization into jurisdictions and the subsequent organizational changes reflect a realization that the corporate organization must adapt to a dynamic environment and that the results of changes must be carefully monitored for potential side effects. The work management systems in place, although some are dated, demonstrate an understanding that work force productivity can and should be monitored regularly. The company keeps abreast of compensation trends through its surveys and considers those results in setting wage and salary levels.

The Challenge of the Nineties

It is in the area of expansion and growth that the company faces its greatest challenge. The company is pursuing an aggressive expansion program in its existing service territory as well as actively seeking additional franchise areas. All other things being equal, we believe residents of Maryland (and the other jurisdictions served by the company as well) are better off having gas service available to them. It fosters competition, is one of, if not the most environmentally preferable fuel sources, and is domestically produced.

The catch is "all other things being equal." We believe that in order to support its aggressive expansion program, the company must be equally aggressive in reducing the costs of new construction and their associated effects on rates. At this time, most of the company's efforts in this area are directed toward growth with a much lower level of effort toward reducing costs of new construction. We believe that the effort needs to be balanced until costs have been significantly reduced. Costs per new hookup are running over three times greater than average embedded cost per customer. The company must ask and answer the question, "How close to embedded cost can we bring incremental costs?"

Related to the area of new construction (but also having impacts on other parts of the company as well), TB&A identified opportunities for improvement in the following areas:

- Communications between organizational units, particularly distribution, marketing and customer services.
- Competing methods for addressing the high cost problem.
- Development of an overall program to integrate individual cost reduction techniques.
- Focus on the customer (where the customer in these cases is a builder or contractor).

Coupled with these opportunities is an insufficient emphasis on cost and rate issues and a lack of timely rate studies.

Drawing upon the findings of several of the chapters in this report, we make the following global recommendations, which are of the highest priority:

- The company should make an annual presentation to the Commission of MNG's construction program, its projected effects on rates for a five year period, and annual cost per new hookup objectives for each of the five years.
- To achieve significant cost per new hookup reductions as rapidly as possible, we recommend that the company undertake a detailed review of all aspects of its capital construction program, which would include implementation of programmatic changes to increase efficiency and effectiveness and to reduce costs. We believe the company will require outside expertise to do this and that the Commission and/or its staff should have some involvement in the process.
- The company should also undertake a similar review of the balance of its operations after the former is well under way, again with the use of outside expertise.

We note that the company began such a program with its "quality process", described in Chapter III of this report. However, as at many other companies, WGL fell victim to some of the more common pitfalls of such a program, including an underestimation of the difficulty of bringing about cultural changes and a focus on technical and operational issues at the expense of leadership and management issues.

253-018

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

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**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-5
(ACC-STF-5-1 THROUGH ACC-STF-5-20)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 26, 2007

Request No. STF-5-18:

Please provide the per therm charge and total charges collected under the GRF tariff for the period 1/1/02 through the most recently available.

Respondent: Pricing & Tariffs

Response:

Southwest first implemented its R&D surcharge on March 1, 2006 per Decision No. 68487. The Southwest GRF Surcharge rate effective March 1, 2006 was \$.00113 per therm. On May 1, 2007, the rate was changed to \$.00074 per therm. From March 2006 through November 2007, Southwest collected a total of \$1,074,582 under the GRF tariff.

253-005

**SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504**

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**ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-5
(ACC-STF-5-1 THROUGH ACC-STF-5-20)**

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 26, 2007

Request No. STF-5-5:

Please provide a list of all DSM projects that were under way since 1/1/02, together with the following information about each:

- a. Project summary
- b. Date started
- c. Date completed
- d. Cost-benefit analyses conducted, including annual costs, annual energy savings, how the savings were to be measured, payback period
- e. Actual cost-benefit results including annual costs, annual energy savings, how the savings were measured, payback period

Respondent: Conservation & Demand Side Management

Response:

Table 1 (attached) includes a project summary, date started, date completed, cost-benefit analysis (TRC ratios), and estimated lifetime energy savings by DSM program. Table 2 (attached) lists the annual budget and costs for each DSM program for 2002 through 2007, along with the annual budget for 2008. Please note the Low-Income Energy Conservation program is administered on a fiscal year from July 1 through June 30 to align with the statewide weatherization program.

Actual cost-benefit and energy savings results are unavailable at this time. A portion of the Southwest portfolio of programs was in transitional stages or began late in 2007; however, most or all of the programs will be fully implemented in

(Continued on Page 2)

Response to STF-5-5: (continued)

2008. Southwest will evaluate all the DSM programs following completion of the 2008 program year.

Southwest did not and has not calculated any type of "payback period" for any of the DSM programs. Neither ACC Staff nor the Commission has requested or required this information in any past DSM filings.

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON

Chairman

WILLIAM A. MUNDELL

Commissioner

JEFF HATCH-MILLER

Commissioner

KRISTIN K. MAYES

Commissioner

GARY PIERCE

Commissioner

IN THE MATTER OF THE APPLICATION OF)
SOUTHWEST GAS CORPORATION)
FOR JUST AND REASONABLE)
RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF SOUTHWEST GAS)
CORPORATION DEVOTED TO ITS)
OPERATIONS THROUGHOUT ARIZONA.)

DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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**EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504**

My Testimony in this proceeding addresses a number of issues related to Southwest Gas Corporation's ("Southwest") purchased gas adjustor ("PGA") mechanism. Southwest has proposed to change the size of the band on the monthly PGA rate and my testimony provides Staff's analysis and recommendations regarding this and other PGA mechanism issues.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am an Executive Consultant III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant III.

A. In my capacity as an Executive Consultant III, I conduct analysis and provide recommendations to the Commission on natural gas and other utility matters. A copy of my resume is attached as Schedule RGG-1.

Q. What is the scope of this testimony?

A. This testimony will address Southwest Gas Corporation's ("Southwest") purchased gas adjustor ("PGA") mechanism.

Q. Have you reviewed the testimony of Southwest Witness Frank Maglietti in regard to the PGA mechanism?

A. Yes. I have reviewed his testimony and will discuss his proposed change to the PGA mechanism as part of my testimony.

PURCHASED GAS ADJUSTOR

Q. Please discuss the functioning of the PGA mechanism in recent years.

A. At the time the currently effective PGA mechanism was initially implemented in June 1999, natural gas prices had been relatively low and stable for a number of years. Shortly following implementation, significant changes took place in natural gas markets, leading to higher and more volatile natural gas prices which have made the last five years difficult

1 for regulators, local distribution companies, and consumers of natural gas. Recent years
2 have also provided a stern test of various aspects of the PGA mechanism. Staff believes
3 that in general the PGA mechanism as currently designed and operated has worked well,
4 given the difficult circumstances of recent years. A PGA mechanism by nature
5 determines the manner in which costs are passed through to customers, including such
6 issues as timing and structure of such pass throughs. In a market where the underlying
7 commodity cost has risen from around \$2.50 per mmbtu to \$6.00 or so in recent years, any
8 PGA mechanism is going to reflect those higher costs, which will be passed through to
9 customers in some fashion, the only variance being the manner in which the rising costs
10 are passed along to customers. No PGA structure can change the underlying fact that
11 natural gas prices and price volatility have increased dramatically in recent years. In
12 general, Staff believes that the current PGA mechanism reasonably balances the interest in
13 shielding customers from price volatility with the competing desire to at least to some
14 extent send a price signal to customers regarding the changing level of the underlying
15 commodity costs. Nonetheless, it is a worthwhile exercise to evaluate the on-going
16 operation of the PGA mechanism and whether adjustments are warranted. Southwest has
17 recommended a change to the PGA mechanism, and my testimony below discusses this
18 proposed change and other PGA issues Staff has reviewed.

19
20 **Q. How does the PGA bandwidth aspect of the PGA mechanism work?**

21 A. As currently configured, the PGA bandwidth limits the movement of the monthly PGA
22 rate over a 12-month period. The current PGA bandwidth of \$0.13 per therm means that
23 each month when a new PGA rate is calculated, the new monthly PGA rate cannot be
24 more than \$0.13 per therm different than the monthly PGA rate in any of the previous 12
25 months.
26

1 **Q. Please discuss the history of the PGA bandwidth.**

2 A. When the general PGA mechanism framework now in place was implemented in 1999,
3 the PGA bandwidth was set at \$0.07 per therm for Arizona natural gas local distribution
4 companies ("LDCs"). Given the predominantly low and stable natural gas prices through
5 the 1990s, it was generally expected that a \$0.07 per therm bandwidth would not come
6 into play very often. However, shortly thereafter the price of natural gas rose significantly
7 and became much more volatile, resulting in the PGA bandwidth often limiting the
8 movement of the monthly PGA rate for periods of time. In Decision Number 62994
9 (November 3, 2000), the Commission expanded the PGA bandwidth for Arizona LDCs,
10 including Citizens Utilities Arizona Gas Division (UNS' predecessor) to \$0.10 per therm.

11
12 Since that Decision the Commission has changed the PGA bandwidth in individual LDC
13 rate cases several times. In Southwest Gas' rate case that concluded in February 2006, the
14 Commission expanded Southwest's PGA bandwidth to \$0.13 per therm. In Duncan Rural
15 Services' rate case that was concluded in March 2006, the Commission expanded
16 Duncan's PGA bandwidth such that the monthly PGA rate can change up to \$0.10 per
17 therm per month, providing the opportunity for the PGA rate to change up to \$1.20 per
18 therm per year. In approving the significant expansion of the PGA bandwidth for Duncan,
19 the Commission cited Duncan's small size and considerable financial constraints. Most
20 recently the Commission expanded the PGA bandwidth for UNS Gas to \$0.15 per therm
21 in Decision Number 70011 (November 27, 2007).

22
23 **Q. Has Southwest proposed a change to the current PGA bandwidth of \$0.13 per**
24 **therm?**

25 A. Yes. Southwest has proposed that the PGA bandwidth be expanded to \$0.24 per therm.
26

1 **Q. Please discuss Southwest's proposal regarding the PGA bandwidth.**

2 A. Southwest's proposal to expand the PGA bandwidth to \$0.24 per therm would allow the
3 monthly PGA rate to automatically track Southwest's changing cost of natural gas more
4 fully than currently is the case, but would also potentially subject customers to a \$0.24 per
5 therm rate increase without any formal Commission review or approval. For comparison
6 purposes, the \$0.24 per therm swing is approximately one sixth the size of the total
7 currently effective per therm residential rate as of December 2007.

8
9 When the PGA bandwidth was initially implemented in 1999, the purpose was to provide
10 a reasonable range for movement of the monthly PGA rate that would capture the
11 changing cost of gas in most instances and also limit the exposure of customers to an
12 automatically changing PGA rate within a one-year period. In the end, to some extent
13 even a PGA bandwidth is limited in its protection of customers, as if gas costs reach a
14 high enough level, Southwest can apply for a temporary PGA surcharge to capture the
15 higher costs that did not fall within the existing bandwidth. In such cases, the nature of
16 the PGA surcharge would be subject to Commission review and approval, providing
17 additional oversight before large gas cost increases are passed along to customers. The
18 previous expansion of the bandwidth from \$0.07 to \$0.10 and then to \$0.13 per therm was
19 a recognition that additional flexibility in movement of the monthly PGA rate was needed,
20 while balancing the need to still provide protection for customers from large automatic
21 changes in rates.

22
23 By nature perspectives on the size of the PGA bandwidth are influenced by the volatility
24 of the natural gas market in recent years. When natural gas markets are seeing a high
25 level of volatility, as was seen in the price runups in 1999-2000 and as a result of
26 Hurricanes Rita and Katrina in 2005, an argument can be made that the bandwidth needs

1 to be expanded significantly. By contrast, since natural gas prices moderated after the
2 2005 hurricane impacts ran their course, natural gas prices, while hardly a model of
3 stability, have fluctuated in a more moderate fashion than during prior recent periods.
4 Looking at Southwest's monthly PGA rate, it has not been constrained by the existing
5 \$0.13 per therm bandwidth since February 2007, when the 12 month average cost was still
6 reflecting hurricane-related events of late 2005. The February 2008 monthly PGA rate is
7 approximately six cents different than the monthly PGA rate in February 2007, indicating
8 that at the present moment, there is still some unused flexibility within the existing \$0.13
9 per therm bandwidth. However, a significant run-up in natural gas prices could quickly
10 change this circumstance.

11
12 **Q. What is Staff's recommendation for Southwest's PGA bandwidth?**

13 A. Staff is cognizant of Southwest's desire for greater flexibility in the PGA bandwidth as
14 well as the need for some amount of checks and balances in how gas costs are passed on
15 to customers, particularly in times when gas prices are high and volatile. In the most
16 recent case involving the PGA bandwidth, the recent UNS Gas rate case, the Commission
17 set the bandwidth level to \$0.15 per therm. Staff believes that expanding Southwest's
18 PGA bandwidth to \$0.15 per therm would be a reasonable balancing of company and
19 consumer interests and is consistent with the Commission's recent action on this issue for
20 Arizona's other large LDC.

21
22 **Q. Did the Company file testimony regarding the PGA bank balance threshold?**

23 A. No.
24

1 **Q. Why is Staff addressing the PGA bank balance threshold issues in its testimony?**

2 A. Both the Commission and the Company have gained additional experience with the PGA
3 mechanism, including the thresholds in recent years, leading to a better understanding of
4 what changes might be made to improve the mechanism. Additionally, a rate case is the
5 proper place to address changes to the fundamental mechanics of the PGA mechanism,
6 and this issue was addressed, and changes made, to the PGA bank balance threshold in the
7 recently concluded UNS Gas rate case. Staff believes the circumstances in this case for
8 Southwest are similar to the circumstances in the recent UNS Gas case in regard to the
9 PGA mechanism, and thus Staff believes this is an opportune time to further refine the
10 threshold levels in the PGA mechanism.

11
12 **Q. Please describe the function of the PGA bank balance threshold within Southwest's**
13 **PGA mechanism.**

14 A. The PGA bank balance threshold identifies the bank balance level, whether over-collected
15 or under-collected, where Southwest is required to take action at the Commission to either
16 address the over- or under-collection, or explain why they should not do so at that given
17 point in time. For Southwest's PGA mechanism, the bank balance threshold was initially
18 set at \$22.4 million by the Commission in Decision Number 61225 (October 30, 1998).
19 Subsequently, the Commission expanded the PGA bank balance threshold to \$29.2 million
20 in Decision Number 68487 (February 23, 2006).

21
22 **Q. Please discuss why the bank balance thresholds were initially created in 1998 and**
23 **1999.**

24 A. At the time the thresholds were initially created, they were created to ensure that PGA
25 bank balance levels did not reach very high levels without any action being taken by the
26 utility. In essence they were a trigger to ensure that the utility and the Commission were

1 aware of and would take action as needed to address the balance. At the time, the initial
2 threshold levels were set at points where it was expected that they would only rarely be
3 breeched. This assumption was based upon the history of natural gas prices through the
4 1990s, when prices were relatively low and stable. Since the initial implementation of
5 these thresholds, the PGA bank balance level has shown much greater volatility than was
6 seen historically, with changes from month to month at times approaching the size of the
7 threshold. The result is that utilities have exceeded the thresholds relatively often in the
8 last 6-7 years. In light of these circumstances, Staff believes that reconsideration of the
9 PGA bank balance threshold levels is warranted at this time.

10
11 **Q. How do you believe the threshold on undercollected PGA bank balances should now**
12 **be approached?**

13 A. In recent years, LDCs that have filed for PGA surcharges have often made such filings
14 before actually reaching the threshold, in anticipation of breeching the threshold in the
15 near future. LDCs have always had the flexibility to file for a PGA surcharge (or credit)
16 at any time as they see fit. With much higher and more volatile natural gas prices in
17 recent years, both the Commission and LDCs are keenly aware of changes in the PGA
18 bank balance and natural gas market conditions. For a larger LDC like Southwest, the
19 Company regularly projects a variety of PGA numbers, including bank balances. Staff
20 believes that these circumstances argue for a change in how the threshold on
21 undercollected PGA bank balances is viewed.

22
23 A review of the month to month change in the PGA bank balance is also helpful in
24 assessing the amount of change that has taken place in the PGA bank balance in recent
25 years. Schedule RGG-2 contains a graph of Southwest's PGA bank balance since January
26 2002 and a graph of the raw size of the change in the PGA bank balance each month.

1 Since January 2002, the largest one month change in the PGA bank balance was
2 approximately \$27.4 million, from the end of January 2006 to the end of February 2006.
3 A total of six months showed a change of over \$20 million from the previous month
4 between January 2002 and December 2007, with an additional four months with swings of
5 between \$10 million and \$20 million. A review of the cumulative change over a seasonal
6 timeframe shows the largest change over a three month period was from January 2002 to
7 April 2002, when the PGA bank balance changed by a total of almost \$69 million. Given
8 this history of large PGA bank balance swings, retention of the current, relatively small
9 threshold levels indicates the Commission is likely to continue to see filings from
10 Southwest to address PGA bank balance levels on a regular basis if there is substantive
11 market volatility.

12
13 Given these circumstances, Staff believes that for Southwest, the Commission should
14 consider eliminating the bank balance threshold in relation to under-collected PGA bank
15 balances. Given high and volatile natural gas prices that appear likely to continue in the
16 near term future, both the Commission and Southwest carefully monitor the functioning of
17 Southwest's PGA, including the changing size of the PGA bank balance. Further,
18 Southwest and other LDCs have shown a strong interest in addressing undercollected
19 PGA bank balances on a timely basis, so it is unlikely that Southwest's undercollected
20 PGA bank balance would grow to very large proportions without action by the Company.
21 Elimination of the threshold on undercollections would, in essence, provide the utility
22 with the discretion to apply for a PGA surcharge when it believes such an action is
23 warranted, while also providing the flexibility for Southwest to avoid such an action if the
24 Company believes changing market conditions do not require such a filing. Staff believes
25 that elimination of the threshold on undercollected PGA bank balances would result in a
26 more smooth operation of the PGA, given the relatively common sizable monthly

1 movements of the PGA bank balance, that at times exceed the size of the threshold itself.
2 Staff therefore recommends elimination of the currently effective threshold on
3 undercollected PGA bank balances.

4
5 **Q. Has the Commission addressed the issue of the threshold on undercollected PGA**
6 **bank balances recently?**

7 A. Yes. In the recent UNS Gas rate case, the Commission approved elimination of the
8 threshold on undercollected PGA bank balances, an action that was supported by both
9 Staff and UNS Gas.

10
11 **Q. How does Staff believe that the threshold on overcollected PGA bank balances**
12 **should be treated?**

13 A. While Staff believes that much of the previous discussion of the threshold on
14 undercollected PGA bank balances also applies to overcollections, there is an additional
15 public interest aspect to avoiding the growth of an overcollected PGA bank balance to
16 exorbitant levels. On the other hand, provision for Southwest to carry an overcollection of
17 some size can help provide a cushion to customers when natural gas market prices rise
18 significantly, as has happened a number of times in recent years. Under the current
19 threshold level, a sizable increase in natural gas market prices will likely result in
20 Southwest swinging to a sizable undercollected PGA bank balance, even if they had a
21 bank balance close to the current threshold requiring Southwest to take action. The
22 current threshold level for overcollections of \$22.4 million is sufficiently small that
23 Southwest could conceivably exceed the threshold, appear before the Commission to
24 implement a credit, and see their balance swing to a sizable undercollection in a short
25 period of time, with Southwest still paying out the credit. Additionally, given volatile
26 market conditions and the size of changes Southwest customers have seen over the past

1 years, a refund over a one year period of \$22.4 million over Southwest's customer base is
2 a relatively small amount per therm, approximately \$0.04 per therm, given recent sales
3 levels.

4
5 Staff believes that the cushioning benefit of having a higher threshold level on
6 overcollections, in addition to the administrative efficiency of not having a threshold level
7 that can be easily exceeded in a month, argues for increasing the threshold level on
8 overcollections substantially. The proper size of such an increase is not entirely clear. In
9 the recent UNS Gas rate case, the Commission increased the overcollection threshold from
10 \$4.45 million to \$10 million. Staff believes that such an increase reflects the increased
11 bank balance volatility, the administrative efficiency of refunding relatively small per
12 therm amounts and the growth in customers and sales experienced by UNS Gas.

13
14 The \$10 million threshold adopted for UNS Gas represented a level of approximately
15 \$0.09 per therm of total gas sales in 2006 for UNS Gas. Staff believes the approach
16 applied to UNS Gas in setting its overcollected threshold would also be reasonable to
17 apply to Southwest. Application of the same approximately \$0.09 per therm of annual
18 sales for Southwest would result in an overcollected threshold of \$55.78 million. Staff
19 believes that increasing the overcollected threshold for Southwest to \$55.78 million is
20 reasonable given Southwest's size and on-going market conditions and recommends
21 adoption of such a level by the Commission. At such a level, Southwest could have a
22 sizable cushion for customers against a run up in market prices, while still providing
23 substantial relief to customers when the higher threshold level is breeched. Staff believes
24 that such a higher threshold is both administratively more efficient given significant
25 market volatility, and provides the possibility of a substantive cushion for movement in
26 the PGA bank balance toward an undercollection before customers would be likely to face

1 a PGA surcharge. Therefore Staff recommends that the PGA bank balance threshold for
2 overcollections for Southwest be set at \$55.78 million dollars.

3
4 **Q. What does Staff believe the net effect of these proposed changes to the PGA bank**
5 **balance threshold will be?**

6 A. Staff believes that over time these changes would result in fewer filings with the
7 Commission to implement temporary PGA surcharges and credits and would provide
8 Southwest with additional flexibility to manage its PGA bank balance, including the
9 opportunity to time PGA surcharge filings with the Commission to the specific
10 circumstances at a given time. For example, currently Southwest is required to come to
11 the Commission to address an undercollected bank balance within specific times frames,
12 even if addressing the PGA bank balance at that time could lead to a surcharge during the
13 coldest months of the winter heating season. Under Staff's proposal, Southwest would
14 have the opportunity to wait until the spring to file for a surcharge, or could, in its own
15 judgment, determine that market conditions are such that it believes a surcharge isn't
16 necessary to pursue at all. While natural gas prices have shown some amount of stability
17 in the last couple years, underlying market conditions make it likely that in the near term
18 future natural gas prices will again experience episodes of significant upward price
19 volatility. Staff's proposals will better position Southwest to weather such episodes, while
20 maintaining necessary protections for Southwest's customers.

21
22 **Q. Southwest has proposed a number of revenue decoupling mechanisms in this case.**
23 **Would those mechanisms have any impact on the PGA mechanism if they were**
24 **adopted?**

25 A. Staff's opposes the introduction of Southwest's proposed revenue decoupling
26 mechanisms, as discussed in Staff Witness Frank Radigan's testimony. Southwest's

1 revenue decoupling proposals could potentially impact the design of Southwest's rates.
2 Because customers would pay a different gas cost per therm for different portions of their
3 consumption under Southwest's rate design-related decoupling proposal, the existing PGA
4 mechanism where a single per therm monthly PGA rate is calculated based on a 12-month
5 rolling average would have to be changed. Given the different gas cost numbers for
6 different usage levels, it is likely that a new PGA mechanism reflecting different tiers of
7 gas cost would be more complicated and less understandable to customers. Introduction
8 of revenue decoupling would also impact at least some of the numbers that are reported in
9 the monthly PGA reports the Commission receives. Staff recommends that if any form of
10 revenue decoupling is adopted in this case, that Southwest review the monthly PGA report
11 and work with Staff to implement any needed changes to the report. Staff further
12 recommends that prior to any introduction of the rate design decoupling mechanism, that
13 Southwest address issues regarding how the decoupling rate design would change the
14 functioning of the PGA mechanism and receive Commission approval of a proposal to
15 change the PGA mechanism to reflect these new circumstances.

16
17 **SUMMARY OF RECOMMENDATIONS**

18 **Q. Please summarize your recommendations.**

19 **A.** My testimony includes the following recommendations:

- 20
- 21 1. The bandwidth on the monthly PGA rate should be expanded to \$.015 per therm.
 - 22
 - 23 2. The threshold on the PGA bank balance for undercollected balances should be
 - 24 eliminated.
 - 25

1 3. The threshold on the PGA bank balance for overcollected balances should be set at
2 \$55.78 million.

3
4 4. If a revenue decoupling mechanism is adopted in this case, Southwest should
5 review its monthly PGA report and work with Staff to adjust the report as
6 necessary to reflect changes resulting from revenue decoupling.

7
8 5. Prior to any introduction of the rate design decoupling mechanism, Southwest
9 must address issues regarding how the decoupling rate design would change the
10 functioning of the PGA mechanism and must receive Commission approval of a
11 proposal to change the PGA mechanism to reflect these new circumstances.

12
13 **Q. Does this conclude your Direct Testimony?**

14 **A. Yes, it does.**

RESUME

ROBERT G. GRAY

Education

- B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Executive Consultant III (November 2007 – present), Public Utility Analyst V (October 2001 – November 2007), Senior Economist (August 1997 – October 2001), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas and other utility issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Prepare recommendations and present written and oral testimony before the Commission on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving as Chair of the NARUC Staff Subcommittee on Gas.

Testimony

- Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.
- Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.
- Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.
- Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

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Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

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Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of Black Mountain Gas Company (Docket No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

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Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-04-0876), Arizona Corporation Commission, 2004.

Southern California Edison, Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee, (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-06-0463), Arizona Corporation Commission, 2007.

Semstream Arizona Propane Acquisition of Black Mountain Gas Company – Page Division (Docket G-03703A-06-0694), Arizona Corporation Commission, 2007.

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Arizona Public Service, Palo Verde Hub to North Gila 500 kV Transmission Lint Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000D-07-0566-00135), 2007.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A, Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

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Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

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Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

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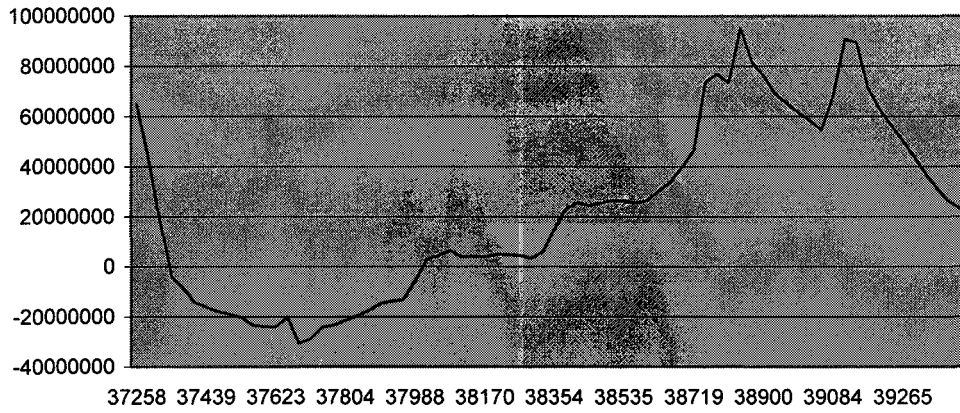
Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6 th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7 th Annual Natural Gas Conference
1999 – 2007	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2008	NARUC Winter Committee Meetings
2004-2007	NARUC Annual Convention

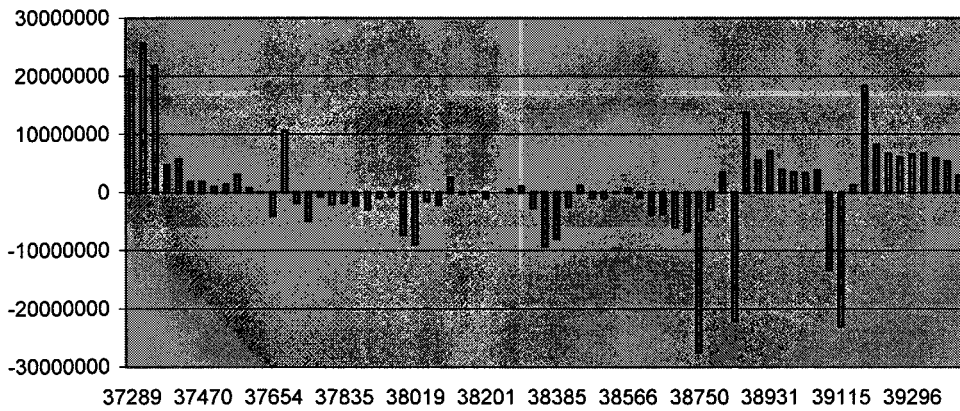
Memberships

NARUC - Staff Subcommittee on Gas – Vice-Chair (2002 - 2004)
 NARUC - Staff Subcommittee on Gas – Chair (2005 - 2007)
 Michigan State Institute for Public Utilities – NARUC Advisory Committee
 NARUC Advisory Council for the North American Energy Standards Board

Monthly PGA Bank Balance



Monthly Change in PGA Bank Balance



BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON

Chairman

WILLIAM A. MUNDELL

Commissioner

JEFF HATCH-MILLER

Commissioner

KRISTIN K. MAYES

Commissioner

GARY PIERCE

Commissioner

IN THE MATTER OF THE APPLICATION OF)
SOUTHWEST GAS CORPORATION FOR THE)
ESTABLISHMENT OF JUST AND)
REASONABLE RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF SOUTHWEST GAS)
CORPORATION DEVOTED TO ITS)
OPERATIONS THROUGHOUT ARIZONA.)
_____)

DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

RITA R. BEALE

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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**EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504**

Together with Mr. Stephen Thumb, Energy Ventures Analysis, Inc. ("EVA") conducted a review during the first quarter of 2008 of Southwest Gas Corporation's ("SW Gas") gas procurement. My testimony focuses on SW Gas' supply portfolio, specifically supply procurement strategies and their effectiveness, the resultant natural gas prices and their prudence, SW Gas' company policies, procedures and practices--during the period of September 2004 through April 2007. I also conducted two audits of: a) selected gas supply transactions and adherence to company policies and procedures and b) the Monthly Bank Balance Statements. A detailed discussion of these topics is developed in Exhibit RRB-2, which is also Chapter 3 of a lengthy report by Energy Ventures Analysis, Inc. For the sake of brevity, my Testimony only summarizes my ten primary findings and ten management recommendations that resulted from the review.

1 **INTRODUCTION**

2 **Q. Please state your name, occupation, and business address.**

3 A. My name is Rita Regina Beale. I am a Principal employed with Energy Ventures
4 Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200,
5 Arlington, VA 22209-1706.

6
7 **Q. Please summarize your educational background and professional experience.**

8 A. I am a graduate of Rider University and the Colorado School of Mines from which I have
9 received a B.S. in Geology and a M.S. in Mineral Economics, respectively. I have
10 consulted to companies from the natural gas utility, electric utility, energy marketing &
11 trading, and oil and gas production sectors for more than five years, initially as a Senior
12 Manager with Arthur Andersen's risk management consulting practice, briefly for my own
13 firm West Hill Group, and currently as a principal with EVA, where I co-direct the oil and
14 gas practice with Mr. Stephen L. Thumb. EVA is nationally known for its work in the
15 energy and emission fields. Early in my career, I spent eight years on Wall Street mostly
16 in the energy commodity business as an oil and gas analyst at various firms including
17 Lehman Brothers and Goldman Sachs. On Wall Street, I had interaction with more than
18 one hundred institutional energy clients including producers, consumers, utilities, and
19 traders. Between consulting firms, I have also been Vice President at two deregulated
20 power companies, responsible for wholesale power transactions, the management of
21 personnel and electricity portfolios. These companies were Idaho Energy LP and First
22 Choice Power LP; I was also involved with the sale of both of these companies. Exhibit
23 RRB-1 presents my resume.

24
25 **Q. What is the purpose of your testimony?**

26 A. Together with Mr. Stephen Thumb, who also is a principal at EVA, I am appearing on

1 behalf of the Staff of the Arizona Corporation Commission (“Commission” or “ACC”)
2 Utilities Division (“Staff”) to address the prudence of Southwest Gas Corporation’s
3 (“Southwest Gas”) gas procurement practices over the time frame spanning September
4 2004 through April 2007. My testimony focuses on Southwest Gas’s gas supply portfolio,
5 specifically the procurement strategies, the resultant prices, company policies and
6 procedures, and two audits namely, a) of the Monthly Bank Balance Statements compared
7 to the GTS¹ and b) of selected transactions vis-à-vis the company’s policies and
8 procedures.

9
10 **Q. Has a complete assessment of your findings been presented in the report attached to**
11 **this testimony in Exhibit SLT-2?**

12 A. Yes. Chapter 3 of Exhibit RRB-2 presents my entire analysis of Southwest Gas’ gas
13 supply portfolio, as well as a number of management recommendations related to my
14 findings.

15
16 **Q. Have you reviewed any relevant external documents as part of the scope?**

17 A. Yes. Part of my preparation included reviewing the testimony of Staff witness William
18 Gehlen submitted to the ACC on July 26, 2005 that covered the prior one year, September
19 2003 through August 2004. I also reviewed a report by Ralph E. Miller submitted by SW
20 Gas to the ACC in July 2006 describing the gas procurement policies and procedures of
21 SW Gas and some of the related industry Best Practices.

22

¹ Gas Transaction System

1 **SUMMARY OF FINDINGS**

2 **Q. What are your findings?**

3 A. In my review of SW Gas' gas supply portfolio and related practices for the audit period
4 covering September 2004 through April 2007, I concluded:

- 5
- 6 ○ Southwest Gas' gas supply strategies were prudent and reasonable.
- 7
- 8 ○ Its gas supply strategies were effective at providing firmness of supply, providing
- 9 price stability, and reducing price volatility, main objectives of Southwest Gas'
- 10 Arizona Price Stabilization Plan ("APSP").
- 11
- 12 ○ The gas supply transactions executed and prices paid were reasonable and prudent.
- 13
- 14 ○ The price indices used by Southwest Gas in setting their natural gas purchase
- 15 prices are standard industry indexes with good market liquidity.
- 16
- 17 ○ EVA is not concerned that Southwest Gas may rely on NYMEX based pricing, as
- 18 this is the leading price benchmark of the U.S. natural gas industry, and it cannot
- 19 be avoided. Furthermore it should continue to be at Southwest's discretion,
- 20 whether it locks fixed prices for the APSP in either one or two transactional
- 21 components.
- 22
- 23 ○ While it would be to the benefit of all market participants to have a larger number
- 24 of transactions reported to industry publications, thereby increasing liquidity of the
- 25 published price indices and theoretically increasing their reliability, each company
- 26 must be responsible to determine its own comfort level and ascertain its risks and

1 rewards before participating in the sharing of its confidential information.

2 Participation is not a trivial matter in today's litigious world.

- 3
- 4 ○ Any decision by the ACC to require utilities to report transaction data to industry
- 5 publications could also have unintended consequences, and thus should be
- 6 carefully examined before mandating participation. If the ACC decided to require
- 7 Arizona regulated gas utilities to participate, for fairness reasons and to level the
- 8 playing field, it would be important to also require regulated electric utilities to
- 9 report as well.

- 10
- 11 ○ Many of Southwest Gas company policies, procedures, and strategies are
- 12 insufficiently documented in official company documents. While the concepts
- 13 embedded in Southwest Gas' policies, procedures, and strategies appear
- 14 reasonable and prudent, curiously one must tend to go to the documents submitted
- 15 by Southwest Gas to the Commission to find the most complete picture of
- 16 company policies, procedures, and strategies. In addition, some policies,
- 17 procedures, and strategies fall short in certain areas by their lack of documented
- 18 official position on certain subjects. Subsequently, five management
- 19 recommendations are provided and summarized in this testimony.

- 20
- 21 ○ The Monthly Bank Balance Statements compare well to the base transactional data
- 22 of the GTS, with the exception of the month of January 2007 when Southwest Gas
- 23 under-scheduled gas commodity by 356,000 mmBtu and Southwest Gas paid a
- 24 premium over market prices to El Paso Natural Gas of some \$400,000. A number
- 25 of changes to the El Paso tariff, the SW Gas tariff, and proactive actions by
- 26 Southwest Gas, discussed in detail in Exhibit RRB-2 Chapter 3 Section on Bank

1 Balance Statements, suggest that a similar scenario is highly unlikely to be
2 repeated in the future. A repeat of such a large cash-out penalty in the future
3 might very well be viewed as imprudent given Southwest Gas' climb up the
4 learning curve since the introduction and implementation of El Paso's new tariffs
5 during 2006 and 2007. Still, Southwest Gas should continue to press EPNG to
6 improve the quality of its 'real time' load estimates that it broadcasts to shippers
7 via EPNG's Electronic Bulletin Board.

- 8
- 9 ○ Southwest Gas did a good job of following its policies and procedures based on an
10 audit of selected transactions described in detail in Chapter 3 of Exhibit RRB-2.
11 However as a result of this audit, EVA has an additional five management
12 recommendations for improvement that are summarized later in this testimony.
- 13

14 **SUMMARY OF RECOMMENDATIONS**

15 **Q. What are the five management recommendations related to your review of**
16 **Southwest Gas' policies, procedures, and practices?**

17 **A.** In my review of Southwest Gas' gas policies and procedures, I concluded that many of
18 Southwest Gas company policies, procedures, and strategies are insufficiently documented
19 in official company documents. A detailed discussion of each recommendation can be
20 found in Chapter 3 of Exhibit RRB-2. The following enhancements are suggested.

- 21
- 22 1. Consolidate all strategies, policies, and procedures into a minimal number of
23 official company documents with sufficient detail such that new employees could
24 read them and immediately perform the bulk of their work.
- 25

1 2. Clarify the APSP supply element by documenting expected volumes and timing
2 for the next one to two years forward. Some companies have found the use of
3 living appendices (to the company policies for instance) helpful to update expected
4 volumes and dates that frequently change. If there is uncertainty, then windows of
5 time or ranges (or percents) of volume might be established instead.

6
7 3. Clarify the precise nature of the APSP strategy. Is it a programmatic hedge, a
8 judgmental hedge, or a hybrid of the two? The precise strategy should be
9 recognized and declared in company policies and procedures to guide employees
10 and decision makers, as well as the ACC's oversight.

11
12 4. Designate the *Arizona Dispatch Guidelines* as the gas buyers' limits and
13 authorization to execute and meet the forecasted daily demand requirement in
14 company policies and procedures.

15
16 5. Company policies regarding the 'unbuying' of gas, as well as the reasons for the
17 policies and the potential consequences, should be reevaluated, and then explicitly
18 documented in official company policies and procedures.

19
20 **Q. Can you please also summarize the five management recommendations related to**
21 **your review of selected gas supply transactions?**

22 **A. Yes. The following enhancements are suggested:**

23
24 1. Ensure all confirmations with gas suppliers, also known as Exhibit A, include deal
25 transaction dates.

26

2. Ensure all confirmations with suppliers, also known as Exhibit A, include dates of the internal approval next to authorized signature.
3. Considerably shorten the time lapsed between deal execution and deal confirmation with gas suppliers.
4. Include a list of attendees present during the solicitation and purchase of the APSP fixed price gas supply element (as well as during selection and approval of the index gas supply element) to ensure independence, proper monitoring, and to improve the quality of the audit trail.
5. Update old master supply agreements that limit the buyers' liquidated damages at 50 cents per mmBtu into supply agreements that are based on true-up to actual market during non-performance.

Q. Should Southwest Gas be required to implement these recommendations?

A. Yes. All (but one) of these management recommendations should be easy for Southwest Gas to implement and document in internal policies by December 1, 2008. Such a near-term date implies that Southwest Gas would be likely to implement these recommendations during the summer and autumn months of 2008 while it was purchasing gas for the next winter season of November 2008 through March 2009. These recommendations take on elevated importance and urgency given Southwest Gas' expected execution of its first-ever financial derivative hedges in 2008. On December 1st of each year, SW Gas submits its *Arizona Annual Gas Procurement Plan* to the ACC, and this seems to be a pre-existing opportunity to show compliance to the ACC. Therefore, Southwest Gas shall file, on or before December 1, 2008, a report with the Commission

1 documenting its compliance with the recommendations above. ACC Staff shall then
2 review Southwest Gas's filing and Staff shall file, as a compliance item in this docket, a
3 report to the Commission on Southwest Gas's compliance with the recommendations
4 above.

5
6 **Q. What was the one recommendation that requires more time?**

7 A. A stickier issue is the 'un-buying' policy. First, Southwest Gas should document its
8 current policy and include it in the report filed by the Commission by December 1, 2008
9 along with the items above. Re-evaluating this policy is likely to take more time. I
10 believe that Southwest Gas is being reactive to circumstances outside of its control and
11 doing what it perceives is best for consumers.

12
13 **Q. What appear to be the reasons for the 'unbuying' policy?**

14 A. Southwest Gas has a company policy of never selling excess physical gas to third parties,
15 for various regulatory and legal reasons that appear to have roots in both FERC, as well as
16 FAS, regulations due to potential negative repercussions as perceived by the company.
17 But Southwest Gas needs to have an internal mechanism to balance its occasional excess
18 gas. It is impossible for any local distribution companies to perfectly predict load for each
19 day and every hour, and since Southwest Gas has no storage capacity to flow its excess
20 gas and because it potentially faces high El Paso Pipeline charges and/or penalties for
21 imbalances, SW Gas uses the concept of 'unbuying' to help optimize its physical portfolio
22 and minimize costs. 'Un-buying' practices can have accounting repercussions such that
23 Southwest Gas may be required to mark-to-market the 'un-bought' gas if it was originally
24 based on firm fixed priced contracts. For this reason, Southwest Gas has a policy of
25 turning back index priced gas first, and second turning back fixed priced gas, if necessary.
26

1 **Q. What should the proper policy be?**

2 A. ‘Unbuying’ appears to be some form of a physical sale, only back to the original seller and
3 potentially for a net settlement. It is a legitimate physical transaction, and in my humble
4 opinion, should not be considered as speculation; however, Southwest Gas has the burden
5 of proof of convincing its external auditors that it is a ‘normal’ transaction according to
6 FAS 133 accounting and reporting standards. This may take some time to sort out for
7 physical transactions. By contrast, there is no reason to expect a legitimate need to
8 ‘unbuy’ any financial derivative transactions.

9
10 **Q. By when should Southwest Gas reevaluate its policy?**

11 A. Regarding reevaluation of the ‘unbuying’ policy and practices for physical gas, Southwest
12 Gas shall file a report with the Commission, on or before May 1, 2009, discussing its
13 review of the unbuying issue and any recommendations Southwest Gas has for
14 Commission consideration. ACC Staff shall then review Southwest Gas’s filing and Staff
15 shall file, as a compliance item in this docket, a report to the Commission on Southwest
16 Gas’s compliance with the recommendation above.

17
18 **Q. Does this conclude your Direct Testimony?**

19 A. Yes, it does.

**RESUME OF
RITA BEALE**

EDUCATIONAL BACKGROUND

Master of Science Mineral Economics
 Colorado School of Mines, 1987
Bachelor of Science Geology, Rider University, 1984 (Phi Beta Kappa Honor Key)

PROFESSIONAL EXPERIENCE

Current Position

ENERGY VENTURES ANALYSIS, INC. – Arlington, VA

Principal

Ms. Beale joined EVA in 2007 as co-head of the oil and natural gas practice with additional specialization in purchased power and hedging strategies.

Prior Experience

WEST HILL GROUP - Aledo, TX

2005 - 2007

Principal

- Analyzed investment costs of new NGL processing plant of ~\$100 million and evaluated whether to use gas compressors or electric motors.
- Negotiated ERCOT power supply contract and structured heat rate terms to meet client's risk management objectives.
- Provided hedge strategy consultation and market timing to end-users.

FIRST CHOICE POWER LP - Fort Worth, TX

2003 - 2005

Vice President, Energy Services

Executive officer with P&L responsibility for physical ERCOT power and financial natural gas. General management & leadership of five areas: (a) wholesale supply and portfolio management (b) customer deal pricing (c) back office settlement of wholesale supply contracts and preparation of General Ledger accounting entries (d) electric load forecasting for >200,000 customers (e) ERCOT market operations/protocols. Served on Risk Management Committee & Sarbanes Oxley Disclosure Committee.

- Working closely with C-level management, turned company around from negative commodity position. Stayed through successful sale of company.

- Acted as de-facto Director of Portfolio managing all commodity & operational risk of energy, ancillaries, and renewable energy as fixed price, basis, and option positions. Led multi-discipline team that structured & negotiated \$800 million in power supply deals that enabled FCP to survive and restart customer acquisition.
- Help set up Special Purpose Entity (bankruptcy remote) to enhance company creditworthiness and serve as collateral for power supply contracts. Administered front office policies and practices to ensure adherence to risk policies and other contractual covenants.
- Managed staff of 22 with operating budget of ~\$2 million. Responsible for annual and quarterly department forecasts and updates.

IDACORP ENERGY LP – Boise, ID

2002 - 2003

Vice President & General Manager, Electric Power

P&L responsibility for physical & financial wholesale power trading, origination, and market analysis reporting to the President.

- Responsible for portfolio management of wholesale power book and exposures in fixed price, basis, index, and option positions in the western USA. Ensured trading compliance with all portfolio VaR limits and risk policies.
- Positions included deal flow from large commercial & industrial customers and a large number of power transmission contracts modeled as options.
- Activities included portfolio (re) valuation and resolution of regulatory & legal contractual issues.
- Led external sale of commodity book through bid process. Locked mark-to-market value to flatten book prior to sale. Reduced department by half to staff of 20 to meet BOD obligations until sale of book.

ANDERSEN LLP – Chicago, IL

1998 - 2002

Senior Manager, Financial & Commodity Risk Consulting

Scoped, priced, and executed engagements as project manager. Fostered relationships with clients to spearhead key initiatives including business strategy, process reengineering and Sarbanes Oxley controls, risk management, and financial valuation.

- Responsibilities included developing and executing business plans, hiring and developing consulting personnel, quality assurance, and client satisfaction.

EL PASO ENERGY MARKETING – Houston, TX

1996 - 1998

Manager, Natural Gas Storage Trading

P&L responsibility for financial & physical optimization of natural gas withdrawals and injections based on embedded optionality. Portfolio included proprietary leases and client asset management on 18 different pipelines in the East, US Gulf, Texas, Midwest, & Canada.

- Established new storage department from inception into operation.

- Developed & implemented rigorous market-based arbitrage pricing tools to determine schedules and extract maximum value in daily & forward markets.

Manager, Structured Transactions

Set-up initial structure desk and related processes to value & price complex physical natural gas transactions that included energy, storage, and pipeline capacity.

- Administered centralized pricing & execution for sales reps at six remote locations.
- Marketed OTC derivatives to personal book of customers.

OIL & NATURAL GAS COMMODITY ANALYST

GOLDMAN, SACHS & CO - New York, NY

1993 - 1995

LEHMAN BROTHERS - New York, NY

1988 - 1993

Conducted fundamental research on global supply, demand, storage, and relevant trends impacting prices. Published price forecasts and trading recommendations for hedgers and specs. Produced research reports, led client teleconference calls, spoke at client conferences, and attended OPEC meetings as industry observer.

**Gas Procurement Audit -In The Matter Of The
Southwest Gas Rate Case (Docket No. G-
01551A-07-0504)**

MARCH 2008

Prepared for:
The Arizona Corporation Commission
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1

EXECUTIVE SUMMARY

Overview

This report was prepared at the request of the Staff of the Arizona Corporation Commission-Utilities Division ("ACC") to address the prudence of Southwest Gas Corporation's ("SW Gas") gas procurement practices over the time frame spanning September 2004 through April 2007. The two chapters of this report serve as Exhibit SLT-2 and Exhibit RRB-2 of the respective testimonies of Stephen L. Thumb and Rita R. Beale of Energy Ventures Analysis, Inc. in the matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rate of Return On The Fair Value Of The Properties Of Southwest Gas Corporation devoted To Its Operations Throughout Arizona, Docket No. G-01551A-07-0504. In this particular context, gas procurement refers to Southwest Gas' portfolio of gas supply and pipeline capacity and the related policies, procedures, and practices. Chapter 2 of this report serves as Exhibit SLT-2 and examines Southwest Gas' pipeline portfolio and related practices. Chapter 3 of this report serves as Exhibit RRB-2 and examines Southwest Gas' supply portfolio and related practices during the audit period.

Findings

The primary findings of the Chapter 2 review of SW Gas' interstate pipeline capacity portfolio can be summarized as:

- The El Paso Natural Gas (EPNG) pipeline tariff (i.e., EPNG tariff effective January 1, 2006, subject to revision) enacted during this time frame represented a total and complete restructuring of interstate pipeline services for SW Gas. This single event appears to have had an impact on nearly every phase of SW

Gas' operations during the audit period. It is difficult to note succinctly the enormity of this change and its impact on SW Gas. In very simplified terms the EPNG system for East of California was converted from a (1) full requirements concept that provided swing services to (b) a system that, in essence, provided no swing services.

- As a result of this new EPNG tariff, the annual fixed charges paid by SW Gas for interstate pipeline capacity did increase appreciably. Subsequently, after extensive efforts by SW Gas and the other East of California customers, the EPNG rates for the various transportation services were reduced from EPNG's initial proposal, such that SW Gas' fixed annual transportation costs did not double, but it did increase about 60 percent.
- SW Gas under this new EPNG tariff did incur additional charges and penalties, but the incursion of these additional charges and penalties appears to be reasonable. Under the new EPNG tariff it is nearly impossible to operate without incurring some additional charges and penalties. At the beginning the optimum economic trade-off between the cost of pipeline services and minimization of additional charges and penalties was probably not knowable. Subsequently SW Gas took a very proactive role in attempting to minimize additional charges and penalties.

The primary findings of Chapter 3 review of gas supply, policies, and procedures can be summarized as:

- Southwest's gas supply strategies were prudent and reasonable.
- Its gas supply strategies were effective at providing firmness of supply, providing price stability, and reducing price volatility, main objectives of SW Gas' Arizona Price Stabilization Plan.
- The gas supply transactions executed by Southwest and prices paid were reasonable and prudent.
- The price indices used by SW Gas in setting their natural gas purchase prices are standard industry indexes with good market liquidity.
- EVA is not concerned that SW Gas may rely on NYMEX based pricing, as this is the leading price benchmark of the U.S. natural gas industry, and it cannot be avoided. Furthermore it should continue to be at Southwest's discretion, whether it locks fixed prices for the APSP in either one or two transactional components.
- While it would be to the benefit of all market participants to have a larger number of transactions reported to industry publications thereby increasing liquidity of the published price indices, and theoretically increasing their reliability, each company must be responsible to determine its own comfort level and ascertain its risks and rewards before participating in the sharing of its confidential information. Participation is not a trivial matter in today's litigious world.

- Any decision by the ACC to require utilities to report transaction data to industry publications could also have unintended consequences, and thus should be carefully examined before mandating participation. If the ACC decided to require Arizona regulated gas utilities to participate, for fairness reasons and to level the playing field, it would be important to also require regulated electric utilities to report as well.
- Many of SW Gas company policies, procedures, and strategies are insufficiently documented in official company documents. While the concepts embedded in SW Gas' policies, procedures, and strategies appear reasonable and prudent, curiously one must tend to go to the documents submitted by SW Gas to the Arizona Corporation Commission to find the most complete picture of company policies, procedures, and strategies. In addition, some policies, procedures, and strategies fall short in certain areas by their lack of documented official position on certain subjects. Subsequently five management recommendations are made and summarized below.
- The Monthly Bank Balance Statements compare well to the base transactional data of the GTS, with the exception of the month of January 2007 when SW Gas under-scheduled gas commodity by 356,000 mmBtu. A number of subsequent events and actions by SW Gas, discussed in detail in Chapter 3 Section on Bank Balance Statements, suggest a similar scenario is highly unlikely to be repeated in the future. Still SW Gas should continue to press EPNG to improve the quality of its 'real time' load estimates that it broadcasts to shippers via EPNG's Electronic Bulletin Board.
- SW Gas did a good job of following its policies and procedures based on EVA's Audit of Selected Transactions described in detail in Chapter 3. However as a result of this audit, EVA has an additional five management recommendations for improvement that are summarized below.

Recommendations

EVA has a total of fifteen recommendations from its review of Southwest Gas during the audit period.

EVA has five recommendations regarding Southwest's pipeline transportation and gas delivery portfolio to increase reliability and ensure that Southwest meets its commitment to serve regulated load during normal, as well during emergency operating conditions, namely:

- (1) SW Gas is attempting to diversify its interstate pipeline capacity portfolio and SW Gas should continue seeking access to storage capacity, particularly market-area storage capacity. Concerning the latter, it is suggested that the Arizona Corporation Commission take a more active role in promoting the development of market-area storage in Arizona.

- (2) SW Gas should increase the documentation and requirements for its transportation-only (T-1) customers.
- (3) SW Gas should make its Daily Forecasting Accuracy Improvement Task Force a permanent entity. SW Gas' policies should also require ongoing validation and back-testing of its daily load forecast, along with its required frequency.
- (4) Until the point that market-area storage becomes a reality in Arizona, it is recommended that the ACC develop and implement policies that would promote the sharing of gas supplies among the major users of interstate pipeline capacity in Arizona during extreme conditions, including gas LDCs and electric utilities.
- (5) While SW Gas has taken efforts to diversify its future pipeline capacity portfolio, it is recommended that SW Gas carefully track the likelihood of LNG imports entering the Southwest gas market and consider gaining access to such supplies, in an effort to diversify its gas supplies and reduce its dependence on the San Juan basin.

From the review of Southwest's policies and procedures, five management recommendations resulted and are discussed in the Policies and Procedures Section of Chapter 3 in detail. The following enhancements are suggested:

- (1) Consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.
- (2) Clarify the APSP supply element by documenting required timing and volumes for the next one to two years forward. Some companies have found the use of living appendices (to the company policies, for instance) helpful to update forward time windows and volume ranges that may change frequently. If there is uncertainty, then windows of time and ranges of volume or duration can be established instead.
- (3) Clarify the precise nature of the APSP strategy. Is it a programmatic hedge, a judgmental hedge, or a hybrid of the two? The precise strategy should be recognized and declared in company policies and procedures to guide employees and decision makers, as well as the ACC's oversight.
- (4) Designate the *Arizona Dispatch Guidelines* as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in company policies and procedures.
- (5) Company policies regarding the 'unbuying' of gas, as well as the reasons for the policies, should be reevaluated, and then explicitly documented in official company policies and procedures.

Five management recommendations also resulted from EVA's review of specific gas supply transactions. The audit methodology and the transaction selection process are

discussed in detail in the Audit of Selected Transactions Section of Chapter 3. The recommendations are:

- (1) Ensure all confirmations with gas suppliers, also known as Exhibit A, include deal transaction dates.
- (2) Ensure all confirmations with suppliers, also known as Exhibit A, include dates of the internal approval next to the signature authorization.
- (3) Considerably shorten the time lapsed between deal execution and deal confirmation with gas supplier.
- (4) Include a list of attendees present during the solicitation and purchase of the APSP fixed price gas supply element (as well as during selection and approval of the index gas supply element) to ensure independence, proper monitoring, and to improve the quality of the audit trail.
- (5) Update any old master supply agreements that cap the buyers' liquidated damages at 50 cents per mmBtu into supply agreements that are based on true-up to actual market during non-performance.

All (but one) of these management recommendations should be easy for SW Gas to implement and document in internal policies by December 1, 2008. Such a near-term date implies that Southwest Gas would be likely to implement these recommendations during the summer and autumn months of 2008 while it was purchasing gas for the next winter season of November 2008 through March 2009. These recommendations take on elevated importance and urgency given SW Gas's expected execution of its first-ever financial derivative hedges in 2008. On December 1st of each year, SW Gas submits its Arizona Annual Gas Procurement Plan to the ACC, and this seems to be a pre-existing opportunity to show compliance to the ACC.

A stickier issue is the 'un-buying' policy. At minimum, SW Gas should document its current policy by December 1, 2008. Re-evaluating this policy could take more time. EVA believes that SW Gas is being reactive to circumstances outside of its control and doing what it perceives is best for consumers. 'Unbuying' appears to be some form of a physical sale, only back to the original seller and potentially for a net settlement. It is a legitimate physical transaction, and in EVA's humble opinion, should not be considered as speculation, however Southwest Gas has the burden of proof of convincing its external auditors that it is a 'normal' transaction according to FAS 133 accounting and reporting standards. This may take some time to sort out for physical transactions. By

contrast, there is no reason to expect a legitimate need to 'unbuy' any financial derivative transactions.

2

EPNG PIPELINE DYNAMICS

Overview

Probably the most significant event during the audit period (i.e., September 2004 through April 2007) for SW Gas was the total and complete restructuring of the El Paso Natural Gas (EPNG) pipeline tariff (i.e., EPNG tariff effective January 1, 2006, subject to revision) and the impact this change has had on the East of California customers and, in particular, Southwest Gas (SW Gas). This single event appears to have had an impact on nearly every phase of SW Gas' operations during the audit period. Furthermore, it is difficult to note succinctly the enormity of this change and its impact on SW Gas. As a result this major change in the EPNG tariff is discussed as a separate item in this report and then cross referenced as appropriate in other sections of this report. Lastly, the concluding sections of this chapter specifically address in detail the various penalties and charges incurred by SW Gas, as a result of this new EPNG tariff.

Background

Historically, the Arizona portion of SW Gas has been dependent entirely upon EPNG for its interstate pipeline services. While, in general, the optimum strategy for a local distribution company (LDC), such as SW Gas, would be to diversify its pipeline services by connecting to two or more interstate pipelines, historically this has not been an option for SW Gas, because of the physical structure of the interstate pipeline system within Arizona.¹

¹ The likelihood that in the future Transwestern will be providing SW Gas with some interstate pipeline services is discussed in a subsequent section of this chapter.

While EPNG has a long and complex history, in rather simplified terms, the pipeline was built to bring San Juan basin gas (i.e., mostly in New Mexico) to Southern California. In order to accomplish such a goal, the EPNG needed to transverse the state of Arizona. In order to gain the cooperation of the various stakeholders in Arizona, EPNG offered to provide various gas buyers all of their required gas loads. At the time these gas buyers were primarily various relatively small communities and cities, some of which were served by SW Gas. These contracts that provided the various Arizona customers with all of their gas requirements came to be known as full requirements contracts. Under these full requirements contracts the Arizona customers were, in essence, charged for the amount of gas they consumed, but were allowed to vary their daily gas usage from minimum load requirements (i.e., usually in the non-winter months) to peak load requirements (i.e., usually during the coldest part of the winter) at no additional charge. In colloquial terms within the industry, this is referred to as 'free swing' capability.²

Initially, this approach worked reasonably well as the Arizona loads were relatively small in comparison to the California loads. For example, during the mid-1980's Arizona gas loads were less than seven percent of California gas loads.³ However, by 2004 because of the significant growth of the Arizona gas market, this relationship changed such that Arizona was 14.5 percent of California's gas loads.⁴

The key factor behind this growth in the Arizona market was the increase of gas requirements for the electric power sector. Between 1995 and 2004 gas consumption for the electric sector within Arizona increased by a factor of 12 (i.e., from 19 to 240 BCF), as during the building boom for gas-fired capacity Arizona installed over 9,200 MW of new gas-fired capacity.^{5,6}

² The East of California customers will argue that these swing services were not free, but rather part of what was contracted for under the full requirements concept and thus, a service for which they paid. Reviewing such an argument and its legal connotations is beyond the scope of this report.

³ Technically, the comparison should be to Southern California gas loads, which would yield a higher fraction. However, comparable data for Southern California is not readily available. In addition, the basic trend would remain the same.

⁴ A similar assessment would apply to relative loads on the EPNG system, except that the fraction would be higher. Comparable data for the EPNG system is not readily available.

⁵ The building boom for gas-fired capacity was from 1999 to 2004 when the U.S. power industry installed over 204 GW of new gas-fired capacity.

⁶ During the 1995 to 2004 period Arizona's residential, commercial and industrial loads also grew, but at only 1.2 percent per annum rate.

From the perspective of an interstate pipeline, the growth in Arizona's electric gas loads was particularly problematic, as gas loads tend to be very seasonal⁷ and, in particular, daily gas burns tend to be concentrated within a few hours of the day. Concerning the latter, it is not uncommon for a gas-fired power plant to consume its entire daily gas requirements in a six to eight hour period. The situation for gas-fired peaking units is even more dramatic, as the peaking units can consume their entire daily load requirements in two to four hours. These are very difficult load profiles for an interstate pipeline, particularly when similar load profiles exist at the same time for a number of plants.⁸

The net result of the combination of (1) the growth in Arizona gas loads, (2) the load concentration within the power sector and (3) the typical load profiles of gas-fired power plants, resulted in EPNG no longer being able to offer 'free swing' services to its Arizona customers, particularly in light of the magnitude of the cumulative 'free swing' services required by the Arizona customers. In effect, providing 'free swing' services of this magnitude would force the pipeline to operate outside an acceptable and safe range. In theory, the pipeline could be forced to exceed either its maximum operating pressure (MAOP) or its minimum operating pressure in order to provide these swing services. The other alternative, in essence, would be a significant system expansion in order to meet peak hour load requirements. Lastly, the use of market area natural gas storage would help alleviate the lack of swing services on the EPNG system, however none exists within Arizona.⁹ As a result, the full requirements approach that existed for so long in the Arizona community had to be replaced with a different approach.

EPNG Rate Case

While the history of the 2005 EPNG rate case is long and complex,¹⁰ in very simplified terms EPNG went to its major California customers and presented a case that the EPNG system could no longer operate under the full requirements concept used for the East of California customers and that it should not propose a major expansion of the system, which would increase pipeline rates for all customers.¹¹ The California customers

⁷ About 25 percent of Arizona's annual electric power gas consumption occurs during the two summer months of July and August, which primarily is required to meet the state's air conditioning load.

⁸ Arizona's gas load requirements for the power sector are dominated by 20 new gas-fired combined cycle units and seven new gas-fired simple cycle units (i.e., peakers).

⁹ The subject of natural gas storage is further discussed in a later section of this report.

¹⁰ See the Appendix for a chronology of events.

¹¹ Because of their access to large amounts of natural gas storage inside the state of California, the California customers, in essence, do not require the use of the full requirements approach. Thus, the

concurred and the combination of EPNG and the California customers then proceeded to convince the FERC staff that a major change was required. EPNG then presented its new rate case, which basically already had been endorsed by the California customers and the FERC staff, to its customers. What followed was a long and drawn out rate case proceeding that involved a major change to how the EPNG system was operated and, in essence, pitted California customers against the East of California customers.

While the operational concept of providing 'free swing' services and thus, the full requirements approach had to come to an end because of the type of growth on the EPNG system, in the viewpoint of some industry observers, including the authors of this report, the effective trade of full requirements contracts for the East of California customers for the pipeline services provided under the new EPNG tariff was not very equitable. Nevertheless, the East of California customers were forced to adapt to an entirely new set of pipeline services on the EPNG system. The enormity of this change, along with the tension between the EPNG and its customers, as well as between classes of customer, cannot be understated. Similarly, the uncertainty over details of how the new EPNG tariff approach would affect various customers and the problems/flaws of what was proposed by EPNG cannot be understated.¹²

In very simplified terms what EPNG proposed for the East of California customers was to convert its system from (a) a full requirements concept that did provide swing services to (b) a system that, in essence, provided no swing services.¹³ This new approach as originally proposed, in essence, requires a customer to take daily gas requirements evenly over the entire day (i.e., 1/24th of the daily requirements each and every hour) without any variance, and any such variances result in additional charges or penalties.¹⁴

California customers were not interested in expanding the EPNG system, particularly when such an expansion would, in essence, be for the benefit of the East of California customers.

¹² The 2005 EPNG rate case may be both (a) the most significant transition ever for an interstate pipeline and (b) one of or the most arduous and contested interstate pipeline rate cases. The only interstate pipeline rate case in the view of the authors of this report that might be comparable would be the Florida Gas Transmission rate case, in the 1990s. In the FGT rate case it was finally agreed to, in essence, split the system into two non-divisible halves, with the first half serving historical customers at a relatively low pipeline tariff, and the second half serving new customers at a relatively high pipeline tariff.

¹³ While the purpose of this report is to provide a broad overview of the transition for the East of California customers, technically the full requirements era came to an end in September 2003.

¹⁴ While no pipeline can provide infinite swing services, other major interstate pipelines have allowed for some swing capability. The Columbia Gas Transmission system, while designed for even hourly gas flows, allows hourly capacity to be 120 percent of even hourly gas flows. Other interstate pipelines have used the '6-percent rule' for hourly gas flow. Under this concept hourly gas flows can be 6 percent of total daily requirements, which mathematically works out to 144 percent of even hourly gas flow. See EPRI, *Natural*

Exacerbating this basic phenomenon of no swing services on the EPNG system was that the concept was extended to every D-code, meter and contract, which on a practical level, creates an operational nightmare for a customer such as SW Gas.¹⁵

In order to avoid such charges and penalties the customer had the alternative to subscribe to a set of premium services, which were (a) very expensive, (b) relatively complicated and (c) very restrictive in their requirements. Concerning the latter, even with the utilization of such premium services a customer still could be subject to penalties.¹⁶

From a customer's perspective, and in particular, a local distribution company, such as SW Gas, it is literally impossible to operate (i.e., meet the needs of their customers) without any swing capability. The primary reason for the latter is the behavior of residential customers, which have peak consumption requirements during the hours they are awake and very limited requirements while they are asleep.¹⁷ A similar phenomenon exists for commercial and industrial customers.

Response By Southwest Gas

Overview

The response by Southwest Gas to the new EPNG tariff is reviewed in the material below. While SW Gas took a number of actions to limit its exposure to additional charges and penalties, SW Gas nevertheless incurred approximately \$6.7MM in additional charges and penalties during the audit period, before any refunds.¹⁸ The

Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination, (TR-101239), September 1992, Chapter 2.

¹⁵ For clarity if there are six supply contracts delivering to a meter and four meters within a D-code, in essence, there can be zero variance from the 1/24th the load concept at any of these points even though the net downstream flow from the D-code may be perfectly in balance.

¹⁶ A case in point is the FTH-3 premium service (i.e., firm transportation with three hours of swing). Under the FTH-3 premium service the customer is allowed to have an hourly burn that is 150 percent greater than its average daily burn, which is not an uncommon occurrence, for up to three hours during the day, but the three hours must be consecutive. Variation from either the 150 percent criterion or the three consecutive hour criterion results in a penalty. This is the least costly of the premium services, as it is only about seven percent more expensive than the standard no variance FTH-1 service, which in turn was priced about 10 percent above similar historical services. The next level of premium services (i.e., FTH-8) cost almost 70 percent more than the FTH-1 service.

¹⁷ Even during the hours when a residential customer is awake there is a significant variance in their hourly consumption patterns.

¹⁸ The total amount of additional charges and penalties before any refunds is highlighted in this report in order to provide the reader with a complete perspective of what occurred during the audit period and the net result of subsequent actions by SW Gas and other East of California customers. One of the final sections of this chapter addresses refunds during the audit period.

following assessment of these charges and penalties is divided into two sections, namely (a) those charges and penalties associated with a relatively unique force majeure situation that existed during the November 30, 2006 to December 4, 2006 time frame (i.e., approximately \$3.4MM) and (b) other charges and penalties during the audit period (i.e., approximately \$3.3MM) – again before refunds.

Other Charges And Penalties¹⁹

Background

The three most significant characteristics of the new EPNG tariff for East of California customers were the following:

- (1) **The Magnitude of Change**: The enormity of the operational changes under the new tariff simply cannot be understated. SW Gas and the rest of the East of California customers simply did not have any prior experience upon which to make optimal decisions concerning the selection of new pipeline services.
- (2) **Uncertainty**: Through the initial period of the new EPNG tariff (i.e., the period of the initial proposal through initial implementation, or most of 2005) there was significant uncertainty over both (1) the cost of the new pipeline services²⁰ and, in some cases, the definition of those services and (2) the implementation of the various additional charges and penalties (i.e., the how and when). The former significantly impeded any effort to minimize overall cost, while the latter made it almost impossible to assess the economic tradeoff between subscribing for a set of premium services and the potential for additional charges and penalties with or without such premium services.
- (3) **Flaws**: EPNG in its new pipeline tariff proposed an entirely new operational concept, which subsequent events would prove had a number of flaws – some of which were significant. For the most part these flaws occurred because of EPNG's objective of carrying out the 'no swing service' concept to the smallest divisible unit (i.e., to individual D-codes, meters and contracts) on its system.²¹ The operational problems and inequities caused by these flaws, as well as the incorrect data, were the subject of intense discussions between SW Gas and

¹⁹ For purposes of this report the phrase 'other charges and penalties' refers to all those additional EPNG charges and penalties incurred by SW Gas during audit period, except those charges and penalties during the cold weather or force majeure event that occurred between November 30, 2006 and December 4, 2007.

²⁰ The major new EPNG pipeline services included the following firm services FTH-1 (i.e., firm service with no swing capability) and a series of firm premium services, such as FTH-3, FTH-8, FTH-12, FTH-16, NNTH-3 (i.e. no notice), NNTH-12, and NNTH-16. Most of these new premium services had unique and rigid definitions and requirements – some of which were counter intuitive. Also, included in the new tariff were interruptible services (IT-1 and IHSW-1) and the use of a new scheduling service, referred to as HEEN (hourly enhanced entitlement nomination).

²¹ The original EPNG proposal for SW Gas included several delivery points that had been abandoned and excluded at least five relatively new taps. These are relatively simplified examples of flaws contained in the original EPRI proposal. Other more complex flaws required the use of hydraulic modeling to fully correct them. Nevertheless, correcting each of these flaws was important to SW Gas in order to minimize other charges and penalties.

EPNG both during the initial review period and subsequent to the implementation of the tariff.

The combination of these three characteristics of the new EPNG tariff left SW Gas in an environment where it (1) had no operational experience with this new and very complex system, (2) did not have a full perspective on the costs of the various new pipeline services until after they made their initial selection of new pipeline services, and (3) lacked almost any appreciation of either the potential for penalties or their magnitude. Concerning the cost of these new services, there was a significant increase. For example, historically SW Gas paid EPNG about \$32 to \$34MM annually for its pipeline services. The initial proposal by EPNG for its new tariff would have increased the cost for a somewhat comparable set of pipeline services to approximately \$70 to \$99MM. Through the efforts of SW Gas and other East of California customers during the review process for the proposed EPNG tariff, this latter cost was reduced to the \$50MM+ range depending upon a number of factors.

The net result was that SW Gas, in order to minimize costs, initially focused primarily on using the less costly FTH-1 service in order to meet its interstate pipeline transportation requirements. While this in hindsight left SW Gas vulnerable to additional charges and penalties, at the time the optimum economic tradeoff between the cost of pipeline services and the minimization of additional charges and penalties was probably not knowable. The rest of the East of California customers were in a similar situation and, for the most part, used a similar initial strategy in selecting a portfolio of new EPNG pipeline services. For example, none of the other Arizona customers initially selected any of the relatively expensive no-notice pipeline services, even though the use of no-notice service very likely would have minimized a customer's exposure to additional charges and penalties.

Further compounding this situation was EPNG's assignment to SW Gas, and other East of California customers, specific capacity rights from both the San Juan basin and the more expensive Permian basin using an EPNG algorithm. This approach basically precluded SW Gas from selecting the optimum set of capacity rights for its customers in that these capacity rights were assigned.²²

²² In the viewpoint of some industry observers, including the authors of this report, EPNG adopted this approach in order to ensure greater utilization of its capacity from the Permian, which on a delivered cost of

Lastly, the California customers were not subject to this predicament concerning both the uncertainty over the various premium services and the potential exposure to additional charges and penalties. This situation for the California customers existed at two levels. Operationally because of their access to considerable market area storage in Southern California, the California customers could easily take daily gas requirements on an even, hourly basis (i.e., 1/24th per hour) and use their access to market area storage to balance any variance between actual consumption levels and even hourly gas deliveries. In addition, the EPNG tariff provided an exemption from these penalties for delivery points with operating balancing agreements (OBA). On the EPNG system these OBA points were basically Topock and Ehrenberg, which is where the California customers take deliveries from EPNG.

Additional Charges And Penalties

While SW Gas' initial selection of pipeline services was reasonable at the time, it nevertheless resulted in additional charges and penalties of about \$3.3MM during the audit period (i.e., before refunds) and potentially these charges could have been larger if it were not for the proactive measures taken by SW Gas during this time frame. Exhibit 2-1 summarizes these various additional charges and penalties and identifies those that subsequently were refunded. Also, while these additional charges have been grouped together for the purpose of the assessment in this report, there are technical differences between the two categories. Probably the most significant practical difference is that EPNG retains all of the additional 'charges', while the 'penalties' are refunded to the customers. While the exact algorithm for the refunding of the penalties is complex, the basic concept is to collect penalties from those customers that exceed EPNG system tolerances and refund it back to those customers who did not exceed system tolerances. Furthermore, from a pragmatic perspective once a customer pays a penalty there is no guarantee that this customer will receive even a partial refund of that penalty. As a result, penalties, as is the case with the additional charges, in essence, represent an additional cost, hence the reason for grouping the two categories in this report. For completeness, Exhibit 2-1 identifies which categories of additional charges and penalties are retained by EPNG and which are subject to refund. The Appendix provides a more complete definition for each of these various additional charges and penalties.

gas basis is a more expensive alternative. Historically, utilization of this Permian capacity had been problematic for EPNG.

In simplified terms, EPNG invokes penalties at three different levels, namely (1) system wide daily balancing penalties,²³ (2) daily and hourly balancing penalties at individual meters (i.e., MDO and MHO) and (3) more severe penalties during critical operating conditions,²⁴ that are declared by EPNG. While on any given day a customer can incur penalties at all three levels, the actual charge is the highest of the three categories and not the cumulative amount. As illustrated in Exhibit 2-1, the daily variance penalties²⁵ and the charges at individual meters or taps (i.e., MDO and MHO), account for 75 percent of the total charges and penalties during the audit period. These items are further discussed in the material below.

Exhibit 2-1. Additional Charges And Penalties Paid By Southwest Gas During The Audit Period

Category of Charge/Penalty	Cumulative Amount of Charge/Penalty (\$000)	Retained By EPNG	Subject To Refund
Daily Variance ⁽⁶⁾	\$1,203	Yes	-
MDO ⁽²⁾ Violation Penalty ⁽⁶⁾	\$730	-	Yes
MHO ⁽³⁾ Violation Penalty ⁽⁶⁾	\$571	-	Yes
Hourly IHSW ^{(4),(6)}	\$242	-	Yes
Daily Overrun ⁽⁶⁾	\$217	Yes	-
COC Imbalance Charge	\$189 ⁽¹⁾	Yes	-
Hourly Overrun ⁽⁶⁾	\$112	-	Yes
Hourly Scheduling Penalty ⁽⁶⁾	\$58	-	Yes
SOC Imbalance Charge	- ⁽¹⁾	Yes ⁽⁵⁾	-
Emergency COC Imbalance Charge	- ⁽¹⁾	Yes	-
Subtotal	\$3,322		
Refunded Items⁽⁷⁾	(\$1,734)		
Net	\$1,588		

(1) Excludes COC charges during the force majeure event of November 30, 2006 to December 2, 2006, which are discussed in a subsequent section of this chapter.

(2) Maximum daily overrun at individual taps.

(3) Maximum hourly overrun at individual taps.

(4) Interruptible swing service.

(5) Complex.

(6) Fully or partially refunded item.

(7) Excludes interest.

Source: Southwest Gas.

²³ This category can be divided into scheduling penalties that are authorized and daily variations that are unauthorized.

²⁴ Technically, there are two categories of critical operating conditions, namely the less severe Strained Operating Condition (SOC) and the more severe Critical Operating Condition (COC).

²⁵ After considerable effort by SW Gas and the other East of California customers these daily variance penalties eventually were refunded at the end of the audit period.

Actions By Southwest Gas

As previously noted, SW Gas has been proactive during the entire test period in taking actions to either minimize or eliminate these additional charges and penalties. These proactive efforts by SW Gas included:

- Intense efforts to have EPNG correctly assign or modify MDO and MHO levels for various taps;
- Efforts to revise various segments of the EPNG tariff; and
- Judiciously increasing the level of premium services over time.

Penalties For Individual Meters

Under EPNG's new tariff the concept of no swing capability was transferred down to the lowest possible level on the pipeline system, namely the individual meter. As a result, any variance in either daily gas loads from designated levels at an individual meter (MDO) or even hourly loads (MHO) at an individual meter resulted in a penalty under EPNG's system. In addition, the MDO and MHO levels were assigned by EPNG based upon an internal EPNG assessment that was derived from a historical usage algorithm. Subsequently, it was proven that EPNG's assessment for several meters was in error. Furthermore, this concept was extended downstream to each supply contract behind a given meter,²⁶ which made the implementation of the EPNG tariff even more complex and operationally almost a nightmare. Lastly, the concept also was applied upstream to the EPNG D-codes.²⁷ As illustrated in Exhibit 2-1, the combined MDO and MHO charges and penalties represent the largest single category of charges and penalties and account for about 39 percent of the total before refunds and 65 percent of the total after refunds.

Because of certain characteristics of the EPNG system, SW Gas, more than any other East of California customer, is affected by the MDO and MHO provisions in the EPNG tariff. This occurs because SW Gas takes gas from more points (i.e., taps) on the EPNG system than all the remaining East of California customers combined.²⁸ This unusual situation is, in large part, an artifact of the full requirements era for the EPNG pipeline.

²⁶ For example, if there were six separate supply contracts to provide gas to a given meter, then variances for each contract would be tracked and these variances could result in additional charges and penalties.

²⁷ In simplified terms a D-code is a group of meters that are usually within close geographic proximity.

²⁸ SW Gas has approximately 215 taps on the EPNG system that have active EPNG telemetry and approximately 120 taps that Southwest reads on monthly basis (i.e., charts) with this data manually provided to EPNG.

During the full requirements era, EPNG was required to meet all SW Gas gas supply requirements. As a result, when new communities emerged as part of the overall growth within the state SW Gas would need additional gas supplies at a series of new locations, and EPNG would extend its system to these new locations and provide a new tap. At the time having EPNG extend its system and incur the additional capital costs appeared to be the preferred alternative to SW Gas extending its system to connect to EPNG and incurring the capital cost. While EPNG was obligated to complete system extensions even if it involved relatively small volumes and relatively small laterals, the net result was that over time parts of EPNG began to appear more like a local distribution system than an interstate pipeline, and SW Gas had a large number of taps on the EPNG system. An alternative approach, which is common to many LDCs, is to have a series of large city gates that take gas from one or more interstate pipelines at each city gate, and then build downstream pipelines from these city gates to the various load points for the LDC. While in hindsight now that the full requirements era has come to an end, it might be considered desirable for SW Gas to have built a series of city gates and associated downstream pipelines, that is not what happened and it cannot be reversed – at least economically.

The other East of California customers are not faced with a similar situation. This is particularly true of the Arizona electric utilities, which have large point loads that only require a single tap for each point load. Furthermore, with respect to the MDOs for the taps serving electric utilities initially the values assigned by EPNG for these MDOs were based upon a historical usage algorithm, as was the case for SW Gas. Because most Arizona electric loads have grown – in some cases substantially – the assigned EPNG figure based upon historical usage was inadequate for most electric utilities (i.e., this also was true for many SW Gas taps). However, this dilemma was rectified for most of the electric utilities as a net result of the Santan pipeline²⁹ transfer. In simplified terms when Salt River transferred the Santan pipeline to EPNG, Salt River was able to secure an MDO that met the current full load requirements of its power plant site.³⁰ Subsequently, EPNG, in order not to discriminate among electric utilities, allowed most of the electric utility MDOs to reflect the current full load requirement of the various power plant sites. The same was not done for SW Gas and, as a result, there is a

²⁹ Also referred to as the East Valley Lateral.

³⁰ See Docket No. RP05-422-024, Protest of Southwest Gas Corporation of El Paso MDO Procedures Compliance Filing, January 28, 2008.

significant disparity among the East of California customers with respect to EPNG's MDO provisions.³¹

The combination of SW Gas being uniquely affected by EPNG's MDO and MHO provisions and its overall desire to minimize additional charges and penalties has led SW Gas to vigorously pursue correcting various flaws in EPNG's overall process of assigning MDO levels and changing MDO levels wherever possible to represent current SW Gas load conditions.

The number of actions taken by SW Gas on this matter is difficult to summarize because of both the large number of actions and the enormous variety of actions taken, as the circumstances for the nearly 335 SW Gas taps tend to be site specific. In general, this process requires SW Gas to identify flaws with EPNG's MDO/MHO provisions and make a filing with EPNG for a correction and/or a waiver of penalties. Each action can be a rather lengthy process as (1) the burden of proof is on SW Gas, (2) hydraulic modeling of the EPNG system is required in some cases, (3) the request and supporting information usually has to be reviewed verbally with the EPNG staff, (4) a formal request must be filed with EPNG and (5) a formal response must be received from EPNG.

With respect to the large number of actions taken by SW Gas, its Planning Department maintains a three-inch notebook, which is nearly full.³² The material in this notebook documents each of the requests made to EPNG on the MDO/MHO provisions and the resulting outcome. To date SW Gas has been successful in obtaining MDO/MHO increases at approximately 145 metering points, which has been a significant factor in minimizing future charges and penalties. Exhibit 2-2 provides highlights for a few of these actions.

As a practical matter while the charges and penalties associated with EPNG's MDO/MHO provisions have been reduced by various actions by SW Gas, in the future it is highly unlikely they will go away for SW Gas. This assessment is based upon the following factors, some of which are unique to SW Gas.

³¹ See FERC Order Dismissing Requests for Rehearing and Clarifying MDO Procedures issued December 20, 2007.

³² See *Southwest Gas/EI Paso Natural Gas MDO/MHO*, which is retained by Southwest Gas' Planning Department.

Exhibit 2-2. Selected Example Of Southwest Gas' Efforts To Minimize MDO/MHO Penalties

Description	Location	D-Code/Meters
<ul style="list-style-type: none"> Corrected MDO and MHO levels that were incorrect.⁽¹⁾ 	North Loop Substation and Ft. Huachuca	Meter No. 31682 in D-Code 475643 (DSWGN78) and Meter No. 31692 in D-Code 475585 (DSWG HCH)
<ul style="list-style-type: none"> Requested shifting MDO rights in order to resolve apparent deficiencies on the EPNG system that resulted in penalties during January 2007 and that these penalties be waived. Basically a request to allocate unutilized MDO/MHO rights from a downstream meter to an upstream meter under the 'walk the pipe' concept.⁽²⁾ 	Bell Road City Gate, Glendale City Gate, Lateral 25 City Gate	Meter Nos.: 31656, 30433, and 30249.
<ul style="list-style-type: none"> Requested revision to peak-day requirements for SW Gas on EPNG system at individual meter levels. Required submittal of 2,748 data points. Request five relatively new taps, excluded by EPNG, be added.⁽³⁾ 	Entire System	New taps: Robson, Red, New Whetstone, Arivaca Junction, and 7E.
<ul style="list-style-type: none"> Notified EPNG that because of maintenance a meter would be out-of-service and loads would shift to a second meter. SW Gas still incurred penalties despite notification. Subsequently, SW Gas requested a waiver of penalties, which EPNG granted after performing hydraulic modeling which indicated that the requested shift in loads had a positive effect.⁽⁴⁾ 	Duval City Gate	Meters No. 30657 and No. 31524 in D-Code 216811 (DSWG TUS).
<ul style="list-style-type: none"> Submitted bid for additional MDO/MHO levels and challenges requirement to demonstrate 'nameplate maximum burn capability' (i.e., requirement), which primarily pertains to electric generators.⁽⁵⁾ 	Numerous	Numerous.
<ul style="list-style-type: none"> Requested notification of hardware modification in order to obtain at least meter capacities equivalent to EPNG's original MDO allocations.⁽⁵⁾ 	Numerous	Meter Nos.: 20-003, 20-006, 20-019, 20-024, 20-103, 20-105, 20-142, 20-353, 20-427, 20-496, 20-528, 20-594, 20-612, 34-719, and 34-806.

Exhibit 2-2. Selected Examples Of Southwest Gas' Efforts To Minimize MDO/MHO Penalties

Description	Location	D-Code/Meters
<ul style="list-style-type: none"> Requested a combination of D-codes in close proximity in order to better reflect system flow requirements.⁽⁵⁾ 	Yuma Lateral	DSWG-N78 and DSWG-578; DSWG YUM, DSWG COG, DSWG YIR, and DSWG WIL.
<ul style="list-style-type: none"> Requested a change to the MDO/MHO among various delivery points and an increase at another delivery point in order to better represent system operations. While the change was granted, SW Gas still received penalties and subsequently had to seek a waiver.⁽⁶⁾ 	Chandler No. 1 and Foothills Club	Meters No. 30029 and 34790 in D-Code 216808.
<ul style="list-style-type: none"> Increased MDO/MHO levels for meters in the Tucson area in order to more accurately reflect area growth and current load conditions.⁽⁷⁾ 	Tucson, AZ	Meters No. 30148, 30149, and 31518.
<ul style="list-style-type: none"> Increased MDO/MHO levels for meters in the Phoenix area in order to more accurately reflect area growth and current load conditions.⁽⁸⁾ 	Phoenix, AZ	Meters No. 30249, and 30433.
<ul style="list-style-type: none"> Requested hydraulic modeling for potentially constrained laterals and other areas in order to identify where MDO rights can be increased without impairing system operations and what capital improvements might be required to alleviate such constraints.⁽⁹⁾ 	Numerous	Numerous

(1) See EPNG Notice ID: 6489.

(2) See Steve Williams memorandum dated January 29, 2007.

(3) See Richard Jordan memorandum dated December 30, 2006.

(4) See EPNG Notice ID: 6440.

(5) See Steve Williams memorandum dated May 31, 2006.

(6) See EPNG Notice ID: 6577.

(7) This is the net result of a relatively long and drawn out process from May 2006 to December 2007. On average this resulted in a 50 percent increase.

(8) This is the net result of a relatively long and drawn out process from May 2006 to December 2007. On average this resulted in a seven percent increase.

(9) See Richard Jordan memorandum dated June 18, 2007.

- **Large Number of Taps:** SW Gas has a very large number of taps, which among East of California customers is a feature unique to SW Gas.
- **Current Load Profile:** EPNG's historical usage algorithm does not reflect SW Gas' current load profile at many of its taps and SW Gas was not granted relief on this matter, which was done for the East of California electric utilities.
- **Reticulated System:** Portions of the EPNG system are reticulated, consequently loads between meters can shift, as a result of changing pressure in other parts of the EPNG system. While SW Gas has no influence on such system pressure changes and the net downstream result is that the scheduled amount of load is unchanged, under EPNG's rigorous accounting oriented MDO/MHO provisions SW Gas will still incur a penalty for that meter which had higher than expected loads, and no credit for the meter with lower than expected loads, even though the two variances are offsetting.³³

EPNG Tariff Revisions

In addition to representing a major change in operational requirements, the new EPNG tariff as originally proposed has been very difficult to implement for the East of California customers and, in particular, SW Gas. SW Gas has been an active participant, and in some cases the leading participant, in attempting to revise the new EPNG tariff to reduce the difficulty in implementing it, to minimize its operational complexity and to reduce the exposure to additional charges and penalties. While a thorough discussion of these actions and a detailed examination of some of the relatively technical issues involved in such actions is beyond the scope of this report, SW Gas has been very active in the regulatory arena in seeking revisions to the EPNG tariff. This has involved active participation in technical conferences, as well as rate case settlement discussions. Some of the results to date include:

- The creation of the 'dead band' for hourly scheduling, which helps minimize other charges and penalties;³⁴
- The elimination of daily variance and hourly overrun penalties;³⁵
- The revisions of definitions for SOC and COC conditions, as well as critical parameters for these conditions (e.g., minimum and maximum line pack);
- The rejection of EPNG's proposed set of non-critical condition penalties;³⁶
- The ongoing efforts to establish firm rights to the meter;³⁷

³³ This two meter example is a relatively simplified example. Under actual operating conditions the variances caused by other operating conditions in a reticulated system can be relatively complex and involve several meters. Furthermore, hydraulic modeling may be required to fully quantify the impacts.

³⁴ The 'dead band' concept creates a tolerance level for hourly scheduling of 200 Dth or 13 percent, whichever is higher.

³⁵ These are the penalties that were refunded at the end of 2007.

³⁶ See Docket No. RP07-511.

- The creation of the MDO transfer concept, which helps minimize MDO/MHO charges and penalties;³⁸ and,
- The ongoing efforts to have the flow requirements for meters in reasonable close proximity to be treated as a group rather than individually.

These actions are in addition to SW Gas' continuing efforts to proactively notify EPNG of maintenance conditions in order to avoid penalties and to continue hydraulic modeling in an effort to enhance EPNG's assessment of constrained lateral systems.

Premium Services

Another area that SW Gas has pursued in order to minimize charges and penalties is the judicious increase in the utilization of EPNG's more expensive premium services. When these premium services were first proposed by EPNG there was uncertainty over their exact cost and SW Gas had no relevant experience to assess the economic tradeoff between (1) the higher cost for these premium services and (2) the potential cost of additional charges and penalties. Once SW Gas had some operational experience with the new EPNG tariff, it was able to assess the likelihood and magnitude of the additional charges and penalties, and thus, the economic tradeoffs.

Exhibit 2-3 places into perspective the cost for EPNG's pipeline services over the audit period.

As illustrated in Exhibit 2-3, historically SW Gas paid EPNG for its pipeline services about \$33MM. Based upon EPNG's initial proposal for its 2005 rate case the cost of these services would have increased by a factor of two to three times, with the upper end of the range based upon the assumption that all future pipeline services would be the premium no-notice services. There was considerable uncertainty over the final rates for the various services contained in the initial 2005 EPNG rate case. As a result, Category III in Exhibit 2-3 provides a better indication of what likely was expected for 2006 (i.e., about \$54 million). A key attribute of this Category III estimate is that it assumes no premium services and it results in about a 65 percent increase in total pipeline fixed charges over what had been paid historically.

³⁷ See Docket No. RP05-422.

³⁸ See Docket No. RP07-707.

Exhibit 2-3. Historical Perspective On Southwest Gas' Costs For Pipeline Services

Category	Cost of Basic EPNG Services (Million \$)
I. Actual 2005 annual fixed cost prior to placing into effect on January 1, 2006 the rates emanating from the 2005 rate case filing.	\$32.6
II. Estimated annual fixed costs based upon the initial proposal for the 2005 rate case.	\$70 to \$99 ⁽¹⁾
III. Estimated 2006 annual fixed costs assuming no FT-1 conversions and the loss of SW Gas legacy contracts. ⁽²⁾	\$53.9
IV. Estimated 2008 annual EPNG fixed charges after 1st conversion to FTH-3 hourly service. ⁽³⁾	\$52.0
V. Hypothetical 2008 annual EPNG fixed charges after 2 nd conversion to FTH-3 and FTH-8 hourly services. ⁽³⁾	\$53.1
VI. 2008 annual EPNG fixed charges after actual conversion to FTH-3, FTH-8 and NNTH-3 hourly. ⁽³⁾	\$54.5

(1) The higher figure reflects converting all existing FT-1 contracts to NNTH-3 (i.e., no-notice) contracts.

(2) Legacy gas contracts are Article 11.2 vintage rate capacity.

(3) Based upon Settlement rates.

Source: Southwest Gas.

The Category IV figure in Exhibit 2-3 (i.e., \$52 million) estimates what would be the 2008 fixed charges to EPNG and reflects SW Gas' first conversion to some premium services. Subsequently, as part of the second conversion,³⁹ SW Gas added some additional premium services, which increased the overall estimate of the cost for 2008 to about \$53MM (i.e., Category V). Lastly, SW Gas is now testing the use of some no-notice service in its portfolio of pipeline services which will raise the estimate for 2008 to about \$54.5 MM (i.e., Category VI). This is about 4.8 percent higher than the initial estimate provided for 2008 (i.e., Category IV), but it does include more premium services. Concerning the addition of some no-notice premium services for 2008, SW Gas' current plan is to use this service for approximately a year and then to determine if the additional cost is commensurate with its benefit, namely the capability to further reduce the other charges and penalties.

³⁹ As part of the Settlement with EPNG the East of California customers were allowed to convert the initial pipeline services they selected in the 2005 rate case at very specific points in time, which were referred to as the '1st conversion' and '2nd conversion'.

With respect to the unit cost of the various pipeline services included in the various categories contained in Exhibit 2-3, Exhibit 2-4 notes the unit costs for the various pipeline services incorporated in Categories III through VI.

Force Majeure Penalties

Overview

The largest category of charges and penalties were those that were incurred during the November 30, 2006 to December 4, 2006 time frame, when well freeze-offs in the San Juan basin resulted in producers curtailing supplies under force majeure provisions in their supply contracts. While the specific events for this time frame are a little complex, the end result for SW Gas was that it was assessed \$3.4 MM in penalties by EPNG as a result of this event.

Background

While temperatures had been relatively mild for most of November, a cold front quickly moved through the Southwest at the end of November. As illustrated in Exhibit 2-5, this cold front caused temperatures in the San Juan basin to decline about 42°F in approximately 40 hours, with about 60 percent of the temperature decline occurring in the last 18 hours. At the low point temperatures in the San Juan basin reached 5°F.⁴⁰

This decline in temperature caused a loss of production in the San Juan basin, which occurred as a result of the condensate in the gas stream freezing and then plugging flow lines. As illustrated in Exhibit 2-6, average daily flows out of the San Juan basin into the EPNG system were reduced approximately 0.5 BCFD between November 28 and November 30, 2006. As a point of reference, reductions in supply to the EPNG system from the Permian basin were about 0.4 BCFD. By comparison the absolute temperature in the Permian basin, while having declined significantly, only reached 24°F at its low point.

This loss of supply from the San Juan basin caused linepack on the EPNG system to drop dramatically and exceeded the low threshold point for strained operating conditions (SOC), as illustrated in Exhibit 2-7. This placed the EPNG system in a critical operating condition (COC), which is a very serious event for any pipeline.

⁴⁰ A similar phenomenon occurred in the Permian basin, where temperatures declined about 48°F in approximately 16 hours, but the low temperature was only 24°F.

Exhibit 2-4. Unit Costs For Selected EPNG Pipeline Services

Category III

Actual 1/1/06 CDs	Annual Billed Quantity (MDth)	Effective Rates as of Jan. 1, 2006 (subject to refund) Unit Cost (\$/Dth)
Legacy 11.2.a contract	2,045	9.3637
FT-1 Block	780	9.3637
FT-1 Exp	2,014	9.3637
FT-1 1903	892	9.6931

Category IV (Conversion 1)

Actual Nov. 2006 – Oct. 2007 CDs	Quantity (MDth)	2008 Rates (\$/Dth)
Legacy 11.2.a contract	2,363	8.4659
FT-1 Block	780	9.2071
FT-1 Exp	608	9.2071
FT-1 1903	704	9.6786
FTH-3	1,261	9.8398
FTH-8	0	15.5095

Category V (Conversion 2)

Proposed Nov. 2007 – Oct. 2008 CDs Without NNTH-3	Quantity (MDth)	2008 Rates (\$/Dth)
Legacy 11.2.a contract	1,981	8.4659
FT-1 Block	361	9.2071
FT-1 Exp	608	9.2071
FT-1 1903	442	9.6786
FTH-3	2,276	9.8398
FTH-8	48	15.5095

Category VI (Add NNS)

Actual Nov. 2007 – Oct. 2008 CDs With NNTH-3	Quantity (MDth)	2008 Rates (\$/Dth)
Legacy 11.2.a contract	1,981	8.4659
FT-1 Block	361	9.2071
FT-1 Exp	608	9.2071
FT-1 1903	442	9.6786
FTH-3	1,026	9.8398
FTH-8	48	15.5095
NNTH (for FTH-3)	1,250	10.9196

**Exhibit 2-5. Hourly Temperatures At Four Corners Regional Airport,
Farmington, NM – November 28-December 2, 2006**

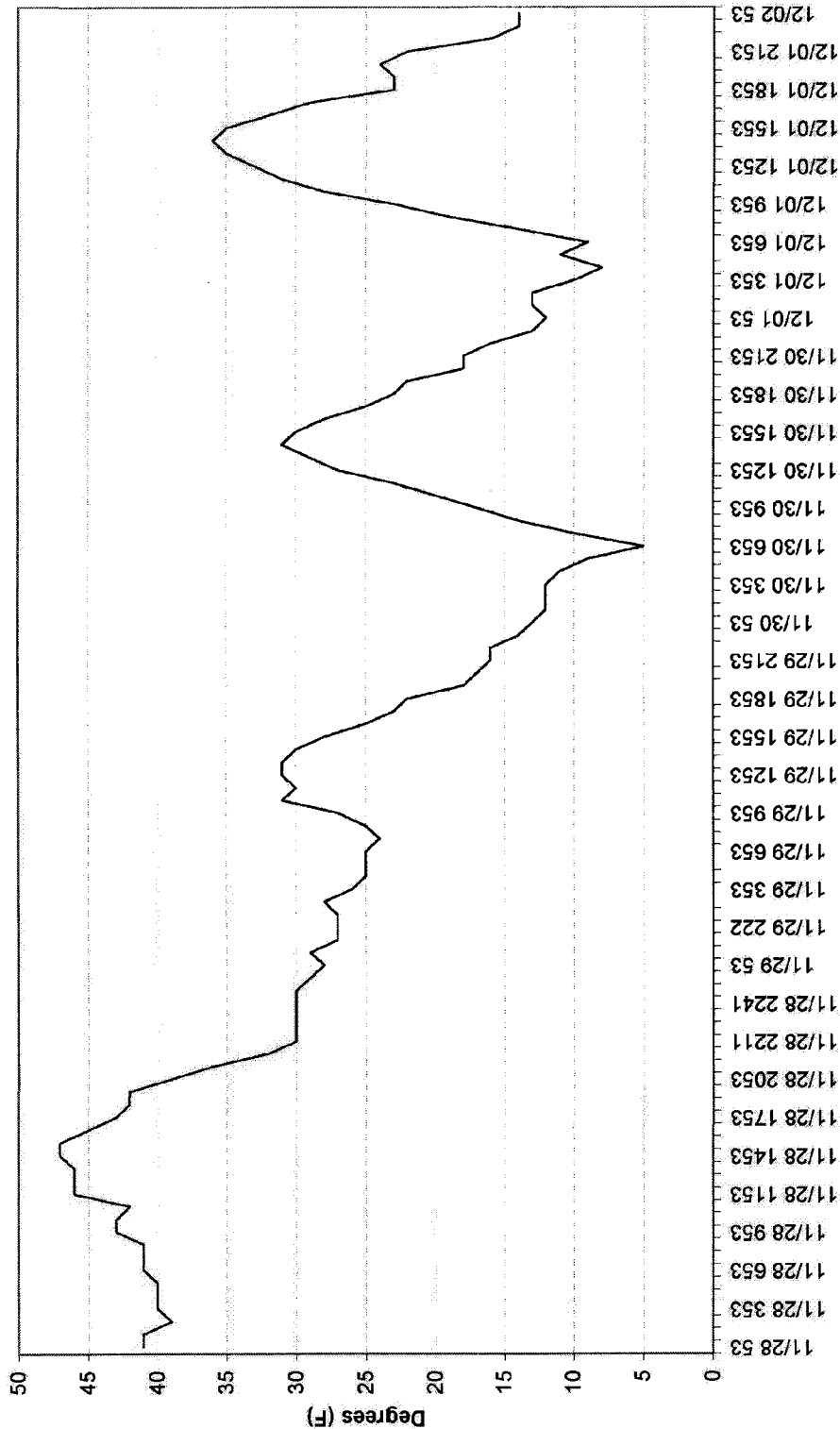
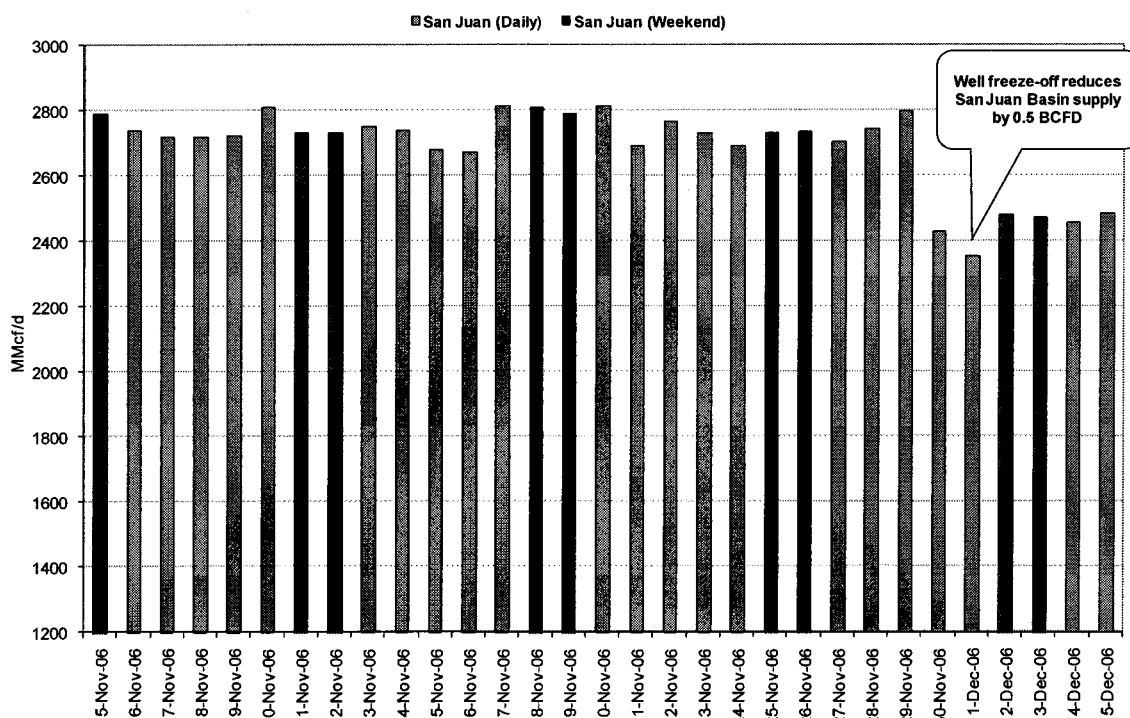
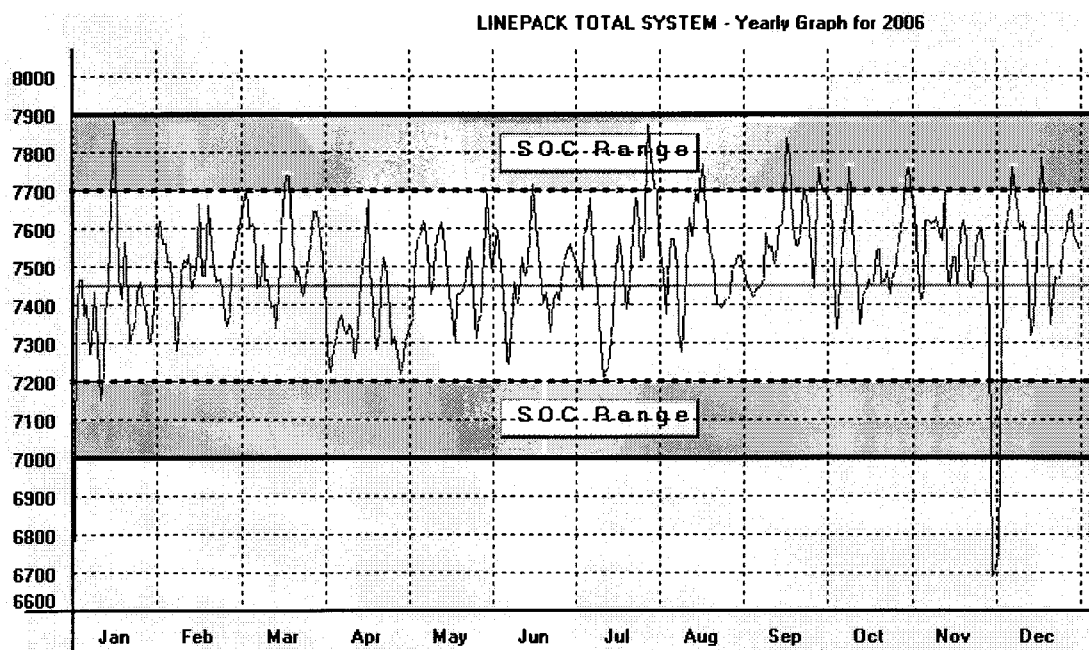


Exhibit 2-6. El Paso Natural Gas Historical Activity



Source: Lippman Consulting.

Exhibit 2-7. El Paso Natural Gas Linepack



Source: FERC Docket No. RP07-511-000, Notice of Intervention and Protest of the Arizona Corporation Commission, Exhibit 1, July 2007.

The speed at which these events occurred – namely the decline in temperature, the loss of San Juan production and the decline in EPNG linepack – appears to have caught almost everyone involved within the southwestern gas industry by surprise.

This rapidly moving cold wave also impacted the major load centers for SW Gas, which in turn caused gas demand to spike. As illustrated in Exhibit 2-8, temperatures in Phoenix declined about 18°F in approximately 15 hours to just above freezing, while in Tucson the temperature declined about 28°F in approximately 15 hours to below freezing (i.e., about 27°F).

Impact On Southwest Gas

The net result on SW Gas of this rapidly moving cold front was (a) that gas demand spiked well beyond forecasted volumes and (b) producers in the San Juan basin invoked force majeure provisions after Southwest Gas had scheduled its gas supplies. Under the rigid requirements of the new EPNG tariff this resulted in SW Gas being assessed \$3.4 MM in penalties, although the figure could have been higher (i.e., about \$7 MM) if it had not been for earlier proactive initiatives by SW Gas and other East of California customers. In addition, subsequent initiatives would have had the net effect of reducing these penalties about 85 percent if the same set of conditions were to occur today. The various components of this event are discussed as separate items in the following material.

Forecasting And Scheduling Loads

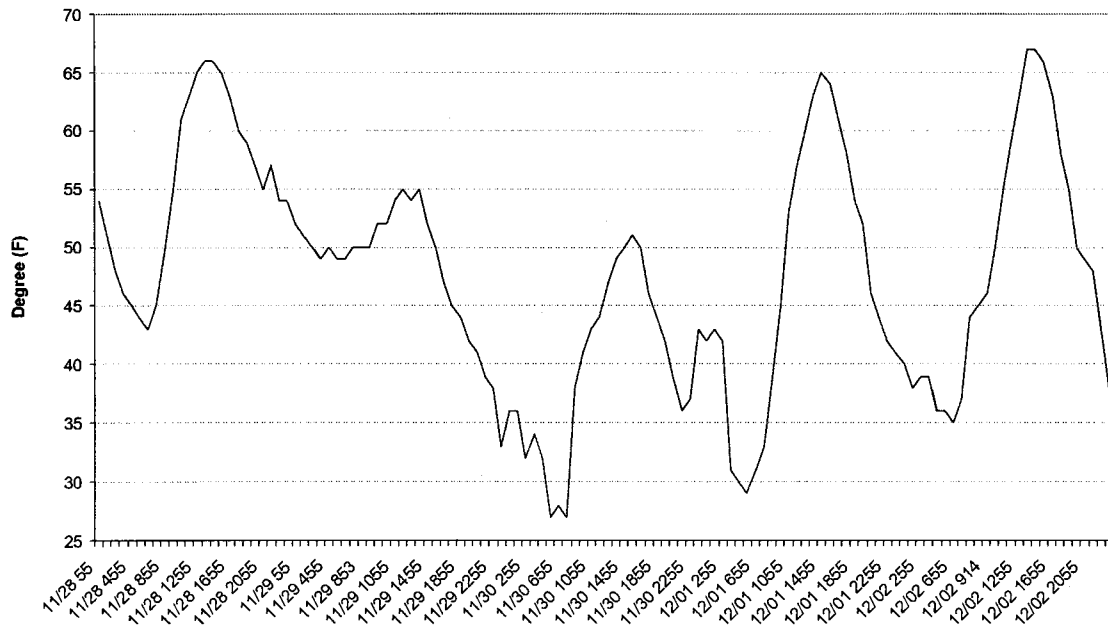
While the primary driver of the subject penalties was the lost production due to the well freeze-offs, load forecasting and scheduling were a part of the overall set of events that occurred during this time frame. Exhibit 2-9 summarizes the various forecast, nomination and scheduling events for November 30, 2006. As illustrated, actual consumption by SW Gas customers on November 30 was approximately 28 percent, or 108,000 Dth, greater than the initial forecast for that day.

Exhibit 2-8. Temperature Profile For Major Southwest Gas Load Centers

Hourly Temperatures
Sky Harbor International Airport, Phoenix AZ
Nov. 28 - Dec. 2, 2006



Hourly Temperatures
Tucson International Airport, Tucson AZ
Nov. 28 - Dec. 2, 2006



Source: NOAA.

Exhibit 2-9. Summary Of Gas Loads During The Force Majeure Event

Description	Amount (000 Dth)	Date	Hour	Temperature (°F)		
				Phoenix	Tucson	San Juan Basin
Initial Forecast	380	11/28	-	54-63	43-68	39-51
		11/29	-	45-57	44-57	27-41
Preliminary Nomination	397					
Scheduling						
Cycle 1	341	11/29	9:30 a.m.	51	52	26
Cycle 2	341	11/29	4:00 p.m.	55	55	28
Cycle 3	392	11/30	8:00 a.m.	38 ⁽¹⁾	27 ⁽¹⁾	10 ⁽¹⁾
Cycle 4	417	11/30	3:00 p.m.	54	50	31
Final Schedule	334					
Final Used	488					

(1) Low temperature for Phoenix occurred at 7:00 a.m. (37°F); for Tucson at 6:00 a.m. (21°F); and for the San Juan basin at 7:00 a.m. (5°F).

Source: Southwest Gas memorandum from Larry Black dated January 30, 2007 and NOAA.

While it may be difficult to chastise SW Gas management for this disparity in light of the rapidly changing weather conditions, no LDC likes to see actual consumption exceed forecasted levels by 28 percent, even under adverse weather conditions. This includes SW Gas, which subsequently set up a multi-department task force⁴¹ to both audit the events of this period and investigate ways of improving its forecasting system. As a result of this task force the following actions were taken:

- **Weather Services:** Historically SW Gas had subscribed to a single weather forecasting service. Starting in 2007 it began subscribing to two weather forecasting services in order to obtain an additional viewpoint on the outlook for weather even though this is an additional expense. A key feature of the additional weather service is that it provides two updates to its initial weather forecast for a given day. The historical weather service only had provided a single weather forecast for each day.
- **GasDay Model:** SW Gas contracted with Marquette University to investigate and make improvements to the GasDay model that was applicable to SW Gas.

⁴¹ The Daily Forecasting Accuracy Improvement Task Force was established in December 2006 and consisted of members from Staff Engineering, Central Gas Dispatch, Gas Purchases and Transport, and Demand Planning. The task force met on a monthly basis through the end of the audit period (i.e., December 2007) and reviewed a number of topics and alternatives for improving SW Gas' daily gas forecasting system.

Among the improvements made to the model, as a result of the multi-step program conducted jointly with Marquette University, was the incorporation into the model nonlinear relationships between consumption and heating degree days at extreme temperatures.⁴²

- **Other Items:** The task force also investigated and implemented the usage of several other supporting analytical techniques to the GasDay model. These include the use of (1) scatter plots and (2) the development of 24-hour load curves for incremental heating degree days. The latter, which could help facilitate with mid-day corrections during the later scheduling cycles, required the receipt of hourly data from EPNG.

Curtailed Gas Supplies

By far the most significant factor behind the penalties assessed for SW Gas during the force majeure event was the curtailment of natural gas production in the San Juan basin. The latter occurred because of the rapid decline in temperatures in the basin which caused a large number of well freeze-offs. While total lost San Juan production on the EPNG system was about 0.5 BCFD, for SW Gas the difference between Cycle 4 scheduling and delivered San Juan supplies was approximately 83,000 Dth.⁴³ The latter is likely the best indicator of lost supply for SW Gas. Furthermore, even if SW Gas had scheduled a higher level of gas supply, it is doubtful that overall supplies would have increased appreciably, as the well freeze-off conditions were epidemic throughout the basin. Instead the amount of curtailed production for SW Gas likely would have increased under a scenario of an even higher level of scheduled supplies by SW Gas.

Under the EPNG system, SW Gas initiates the scheduling process by sending its detailed meter specific scheduling information to EPNG at the designated time (i.e., in this situation Cycle 1 schedules were submitted at 9:30 a.m. on the previous day; see Exhibit 2-9). However, the gas is not officially scheduled at that time, as then EPNG must initiate its confirmation process. Included in this confirmation process is the obtaining of information from the various suppliers as to how much gas supply they will provide at each meter. If the figures provided by SW Gas and the specified suppliers match for a specific meter, then the gas is scheduled. However, if there is a difference, then EPNG notifies SW Gas, which must then begin to initiate corrective action. This process is not instantaneous, as the contact and communication between the various

⁴² See "Excerpts from Demand Planning's Monthly Reports" and "Proposal for the Forecast Model Enhancements Project at Southwest Gas Corporation" prepared by Marquette University dated April 9, 2007.

⁴³ As noted in Exhibit 2-9 Cycle 4 scheduling was about 417,000 Dth. Actual gas delivered by SW Gas was about 333,900 Dth, with the difference being approximately 83,000 Dth, which equated to approximately 0.08 BCFD.

parties takes some time. As a result, until EPNG provides SW Gas with final confirmation of what gas supplies have been scheduled, SW Gas, like other EPNG customers, is in the dark as to actual scheduled quantities of gas and can only use its submitted schedule as an estimate.

During the November 30, 2006 event the flow of information was far from instantaneous, as a result there was both a lack of sound information on the status of scheduled gas supplies and uncertainty over conditions in general. This was particularly true for scheduled supplies from producers, as notification times by producers of their inability to supply contracted quantities of gas supplies varied with some producers declaring force majeure conditions much later than others. The rapid changes in the weather also caught the producers off guard, some of whom attempted to compensate for the loss in production from a given well with production from another well. However, eventually the problem became too great and the producers were forced to declare force majeure and some of these force majeure notifications did not materialize quickly.^{44,45}

By the time Cycle 4 scheduling had occurred, SW Gas had scheduled virtually all of its San Juan basin capacity from firm contracts and had turned to obtaining and scheduling spot supplies from the Permian basin, where well freeze-offs also had occurred. In hindsight it is almost ironic that after all the documentation on scheduled gas supplies finally was received that it was the firm contract supplies from the San Juan that were curtailed, while the spot gas supplies from the Permian were, for the most part, successfully delivered.⁴⁶

Observations

Both the severity of the weather and its rapid change appears to have caught most of the southwestern gas industry off guard, with well freeze-offs forcing producers to declare force majeure conditions, particularly in the San Juan basin. From the perspective of SW Gas, the gas supplies available to serve its customers were limited no matter how much gas it scheduled. SW Gas was limited in its ability to respond to these unusual and rapidly changing events because of the lack of timely receipt of information

⁴⁴ Based upon discussions with SW Gas management.

⁴⁵ Among the producing basins in the U.S. the San Juan basin is relatively unique, because of the large number of wells in the basin (i.e., there are about 35,000 wells in the basin of which about 27,000 are producing), which makes scheduling and confirmation of scheduled gas supplies even more difficult.

⁴⁶ See Larry Black memorandum dated January 30, 2007.

from EPNG and the suppliers. In addition, it appears that even if SW Gas had received this information on a more timely basis, it is doubtful SW Gas could have obtained a significant increase in gas supplies, as the entire region was under the equivalent of emergency conditions. Despite these mitigating factors, under the newly instituted EPNG tariff SW Gas was required to pay \$2.1MM in penalties, as a result of the events for November 30, 2006.⁴⁷

With respect to the penalties they could have been nearly double this amount if SW Gas and the other East of California customers earlier had not prevailed on eliminating the Daily Overrun Charges.⁴⁸ In addition, a subsequent Rate Case Settlement would reduce the amount of this penalty by 85 percent if these exact conditions were to repeat themselves in the future.⁴⁹

With respect to avoiding losing access to gas supplies under future force majeure conditions, independent of concerns about penalties, the only realistic alternative appears to gain access to market-area storage. Unfortunately, none exists within Arizona at the current time. Gaining access to production-area storage could help mitigate supply concerns, particularly on the second day of the event. At present the only production-area storage in the region is in the Permian basin. Unfortunately, the amount of such storage capacity is limited and the standard terms and conditions for such capacity are restrictive. Concerning the latter, both of the two key production-area storage facilities in the Permian basin require that any change in initial nominations for gas to be withdrawn from these storage facilities occur prior to the Cycle 1 scheduling time for EPNG. As a result, access to capacity from these facilities, if it had been available, would not have enabled SW Gas to get additional gas supplies on the first day of the event.⁵⁰ The issue of future access to storage capacity is discussed further in the recommendations section of this report.

⁴⁷ This assessment focuses on the first day of the four day event, namely November 30, 2006. Events for the second day, namely December 1, 2006 were similar and resulted in additional penalties of \$1.2MM. EPNG finally lifted the declaration of strained operating conditions (SOC) at 7:23 a.m. on December 4, 2006. The initial declaration of SOC occurred at 6:38 a.m. on November 30, 2006. Within this time frame critical operating conditions (COC) were declared from 11:22 a.m. on November 30, 2006 to 8:51 a.m. on December 3, 2006.

⁴⁸ Technically the elimination of the Daily Overrun Charges had been agreed to, but not yet implemented formally. However, EPNG waived the additional cost associated with the Daily Overrun Charges.

⁴⁹ February 6, 2008 conference call with SW Gas management.

⁵⁰ For the Enstor's Gamma Ridge storage facility changes to nominations must occur before 11 a.m. on the first business day preceding the day on which such change is to take place (i.e., on November 29 for gas delivered on November 30). For Chevron/Unocal's Keystone storage facility the requirement is before 9

Lastly, the events of November 30, 2006 to December 4, 2006 represent the first time SW Gas had to adapt to a force majeure event without a full requirements contract with EPNG.

Other Related Items

There are a few other items that merit discussion in this chapter even though they are either technically not part of the audit period or not directly part of the EPNG system.

Diversification

While for most LDCs it is desirable to connect to two or more interstate pipelines in order to diversify both access to supply and gas transportation capacity, in the case of SW Gas historically this has not been an alternative. However, in the future because of the proposed expansion of the Transwestern system, as a result of its Phoenix Lateral project, SW Gas will have the opportunity, albeit a limited one, to diversify its future transportation portfolio. Such diversification would help reduce SW Gas' dependence upon EPNG and its somewhat restrictive tariff.

The expected route for the Phoenix Lateral, which currently is scheduled to be completed in 2008, is primarily to the west and south of Phoenix and, as a result, it does not overlap significantly the EPNG system, which would be an ideal circumstance for SW Gas. Key factors in the selected route for the Phoenix lateral appear to be the immense difficulty in gaining right-of-way in the heavily populated areas to the west of Phoenix and a choice to divert the route around the White Tank Mountains. SW Gas has subscribed for capacity at the Sun Valley North, Sun Valley South, New Florence and Gilbert meter stations on the Phoenix Lateral project, as illustrated in Exhibit 2-10. The capacity at these locations primarily will be to serve future growth for SW Gas as each meter is close to master planned communities that are in the process of being developed. Currently there is no EPNG service to these areas.

a.m. on the day such change is to take place. Source: Excerpts from the operating statements for (1) Enstor's Gamma Ridge project and (2) Chevron/Unocal's Keystone project.

Exhibit 2-10. Southwest's Capacity Commitment To Transwestern's Phoenix Lateral

Tap Location	Capacity Commitment in Dth/day		
	Nov-Mar	Apr-Oct	Annual Average
Sun Valley-North	4,350	340	1,999
Sun Valley-South	8,390	660	3,858
Rainbow Valley	10,760	-	4,451
New Florence (Santan)	3,430	-	1,419
Germann (Santan)	47,090	-	19,481
Gilbert (Santan)	980	-	405
Total	75,000	1,000	31,613

Source: Mr. William Moody memorandum to the Arizona Corporation Commission dated February 22, 2006.

In addition, SW Gas has subscribed to capacity on the Phoenix Lateral at the Rainbow and German meters, where currently EPNG also has meters. As a result, service at these two points⁵¹ will be in direct competition to existing EPNG service and if the most economic alternative could allow SW Gas to displace service previously provided by EPNG and potentially avoid exposure to penalties at these two points. Unfortunately, these are the only two points with such potential overlaps and thus competition exists. Lastly, there has been some discussion of moving the Sun Valley North meter to the north and east, if the Phoenix Lateral can be rerouted. If this were to occur, SW Gas would be able to displace current EPNG services at this revised location.

Storage

Independent of the fact that the force majeure events of November 30, 2006 through December 4, 2006 resulted in penalties being assessed against SW Gas, which is an undesirable event, probably the more significant issue is the potential threat to providing adequate service when a similar force majeure event occurs in the future. Under such conditions SW Gas may not be able to have access to adequate gas supplies to meet customer demand.^{52,53} The decline in the EPNG linepack during the November 30

⁵¹ These two meter points account for about 75 percent of SW Gas' capacity on the Phoenix Lateral.

⁵² This issue of well freeze-offs under unusual weather conditions and the subsequent curtailment of production is not unique to Arizona. While hopefully such events will be rare, they can happen and storage is the key tool to compensate for such an event. For the U.S. as a whole the classic examples are: (1) the winter of 1976/1977 and (2) the winter of 1989/1990, when ice flows occurred 12 miles out into the Gulf of Mexico (i.e., see EPRI, *U.S. Natural Gas Industry: Impact of the Winter of 1989/1990* (OCSP-7102), January 1991).

⁵³ Force majeure events have happened in the past in the San Juan basin and very likely will happen again, although predicting the timing of such future events is nearly impossible. Factors that make the San Juan

event was alarming (i.e., see Exhibit 2-7) and SW Gas because of its 'obligation to serve' and its inability to fuel switch⁵⁴ is probably the most sensitive East of California customer to such a phenomenon. While there are few things SW Gas might do to mitigate the impact of a future force majeure event, the primary vehicle for protecting against such circumstances and ensuring SW Gas meets its 'obligation to serve' is to gain access to market-area storage. While currently no market-area storage exists in Arizona, it is possible that some market-area storage could be developed in the future. Since the development of market-area storage likely will be done by third-party developers because the financial costs may be beyond SW Gas' capabilities, it is suggested that the Arizona Corporation Commission (ACC) may want to consider the following items:

- **Project Promotion:** The ACC may want to consider adopting even more proactive policies for the development of market-area storage in Arizona than the policies on this subject have been previously set forth.⁵⁵ While it is realized that there are pros and cons to developing such policies, a more proactive position by ACC is suggested. This could include:
 - (1) definite pre-approval for the cost-recovery associated with subscribing to capacity for such projects,
 - (2) a stipulation the likely increase in costs associated with having access to market-area is in the best long-term interest of customers (i.e., similar to an insurance policy to ensure that the 'obligation to serve' is met under adverse circumstances)⁵⁶ and
 - (3) potentially providing incentives for the development of market-area storage.⁵⁷ In making these suggestions it is realized that any potential market-area storage projects must meet two key thresholds, namely that the storage project is technically sound and that it is financially viable. Also, it is realized that meeting these two threshold requirements will be a challenge and that off-the-wall projects that might be proposed by various promoters are not acceptable.

basin vulnerable to well freeze-offs are (1) the very large number of wells in the basin (i.e., about 35,000 in total), (2) the fact that many of these wells are condensate rich and (3) it can get very cold in the basin (e.g., 5°F).

⁵⁴ Many electric utilities can either directly or indirectly switch to alternative fuels to run their plants, when gas supplies are curtailed. Direct fuel switching involves the use of distillate to fuel the plant, even if just for a single day, while indirect fuel switching involves the use of purchased power on the grid to replace lost gas-fired generation.

⁵⁵ See "ACC Policy Statement Regarding New Natural Gas Pipeline and Storage Costs" dated December 18, 2003.

⁵⁶ The ACC could work with East of California customers to establish tolerable bands of cost increases for such 'insurance policy' projects.

⁵⁷ The incentives could be recoupable depending upon the success of the project.

- **Copper Eagle:** While, in general, the ACC cannot be biased towards any specific market-area storage project, the Copper Eagle site may be an exception because of the very limited alternatives in Arizona.⁵⁸ The suggestion is that the ACC may want to consider either directly or indirectly obtaining an option on the Copper Eagle site and thoroughly investigating the historical challenges to this project. Such a thorough and unbiased investigation could establish that the Copper Eagle site is a viable storage site that has characteristics that are similar to many, if not most, of the existing storage facilities in the U.S.

While no one likes to dwell on worst case scenarios, the potential consequences of the combination of inadequate supplies due to a major well freeze-off event and the lack of access to market-area storage can be significant for the region. In the worst case sections of the SW Gas system likely would lose pressure, which could cause pilot lights to go out. Relighting a large number of residential and small commercial pilot lights is a significant undertaking, which could require action by both SW Gas and state institutions. Similarly, brown outs for electric power could emerge as a result of some gas-fired electric units not being able to either fuel switch or obtain adequate purchased power. The region's sensitivity to the latter has increased significantly as a result of the large amount of gas-fired generation that has been built in Arizona in the recent past.⁵⁹

With respect to items that could be done in the interim until market-area storage becomes available, the following should be considered:

- **New ACC Policy:** Because the natural gas load for electric utilities in Arizona is large and many of these electric utilities have the ability to fuel switch, particularly during periods of constrained gas supplies, it is suggested that the ACC actively pursue developing both a policy and a coordinating committee of industry representatives that would promote the swapping of gas supplies during future periods of curtailed gas supplies. Such a policy would go a long way to ensure that residential gas demands are met under such conditions and that the 'obligation to serve' is met. There will be cost issues involved in such a policy – for example, if an LDC receives gas supplies scheduled by an electric utility under such a crisis mode, the LDC would have to compensate the electric utility at its cost for an alternative fuel (i.e., distillate and/or purchased power). In addition, the committee would have to be a 'standing committee' that is capable of assessing viable alternatives and enacting them quickly once the crisis conditions emerge. Other regions have had success with such efforts. For example, historically the state of Texas has had such a 'standing committee' to respond to well freeze-offs and this committee has had some success in dealing with such events. Similarly, in the New England region efforts to establish and

⁵⁸ In general, the geology of Arizona significantly limits the potential sites for developing storage.

⁵⁹ During the winter of 1989/1990 interstate pipelines were forced to curtail firm transportation and there were rolling blackouts among some electric utilities. See EPRI, *U.S. Natural Gas Industry: Impact of the Winter of 1989/1990* (OSCP-7102), January 1991.

encourage coordination between LDCs and electric utilities has had some success.⁶⁰

- **Diversify Supplies:** It is recommended that SW Gas carefully track the likelihood of LNG imports entering the Southwest gas market⁶¹ and consider gaining access to such supplies, in an effort to diversify its gas supplies and reduce its dependence on San Juan basin gas supplies. Any such effort should be evaluated carefully as there are cost issues involved with obtaining such supplies, as well as infrastructure issues. Concerning the latter, these LNG imports likely will be transported via the Baja pipeline to Erhenberg, which over time likely will make Erhenberg a liquid point for these gas supplies. However, SW Gas will still have to work with EPNG to obtain back haul capacity and a reasonable rate for such capacity.

Refunds

While the subject of refunds is discussed more fully elsewhere in this report, it is noted briefly noted here for completeness. As illustrated in Exhibit 2-1, during the audit period SW Gas did incur \$3.3MM in additional charges and penalties. However, SW Gas also received \$11.2MM in refunds during 2007 (i.e., see Exhibit 2-11) of which approximately \$1.9MM represents refunds of additional charges and penalties.⁶² As previously noted, obtaining these refunds for the various additional charges and penalties required a considerable proactive effort by SW Gas.

Transportation Customers

During the audit period, SW Gas provided service to between 80 and 100 transportation only customers (i.e., SW Gas' T-1 tariff). These transportation customers, which receive supply at about 200 SW Gas meters and are primarily industrial firms, are supposed to arrange for their own gas supplies and interstate gas transportation capacity to the appropriate SW Gas city gate or tap and then pay SW Gas a fee for transporting the gas on its system. This concept emerged during a period in the industry when it was thought that this option for industrial customers would promote flexibility in obtaining gas supplies and thus, aid in reducing the overall costs of end user gas supplies. While the merits of this concept may have been sound during the 'full requirements' era for the EPNG

⁶⁰ See EPRI, *Natural Gas and Electric Industry Coordination in New England* (TR-102948), November 1993.

⁶¹ The Energia Costa Azul regasification project (i.e., one BCFD) is under construction and scheduled to come online about March 2008. In addition, the projects developers have contracted for LNG supplies with Indonesia's Tanguh facility (i.e., online 2008 and 2009) and Russia's Sakhalin Island project (i.e., online in 2008 and 2009). Supplies for the latter likely will be replaced by LNG supplies from Australia's Gorgon facility once it comes online (i.e., estimated to be 2012 or 2013). Only a portion of these LNG supplies will be transported to the U.S., as some LNG supply will be consumed within Mexico.

⁶² The \$1.9MM figure includes an estimated allocation of interest of \$132,000.

Exhibit 2-11. EPNG Refunds To SW Gas For Arizona Operations⁽¹⁾

Category	2006 EPNG Settlement Refund (\$000)	2007 EPNG Settlement Refund (\$000)	Total (\$000)
Reservation Charges	\$4,687	\$4,016	\$8,703
Daily Volume Penalty	\$237	\$967	\$1,204
IHSW Charges	\$83	\$138	\$221
Unauthorized Daily Overrun Penalty	\$69	\$79	\$148
Unauthorized Hourly Overrun Penalty	\$1	\$111	\$112
Usage Charges	\$66	\$36	\$102
Scheduling Penalty	\$2	\$40	\$42
MDO/MHO Penalty	\$44	(\$37)	\$7
Credits ⁽²⁾	(\$33)	(\$91)	(\$124)
Interest	\$532	\$259	\$791
Total	\$5,689 ⁽³⁾	\$5,519 ⁽³⁾	\$11,208 ⁽³⁾

(1) Also, there were \$1.2MM in refunds associated with SW Gas' Nevada and California operations.

(2) Credits include demand charge and capacity release credits.

(3) Figures may not add due to rounding.

pipeline, they create a number of problems under the new EPNG tariff. Among these problems is that variances in even hourly gas loads for these transportation only customers can result in additional penalties for SW Gas. While the additional charges and penalties attributable to these transportation only customers should be allocated back to them,⁶³ such a tracking system takes considerable effort. While the basic components of this concept already have been addressed by SW Gas,⁶⁴ it appears that overall this concept may not have been SW Gas' highest priority in light of all the other items to which SW Gas management had to adapt as a result of the new EPNG tariff.

While no LDC likes to irritate its customers, going forward it is recommended that SW Gas become much firmer with these transportation only customers and require detailed documentation of both gas supply contracts and interstate capacity contracts, even if merely interruptible capacity contracts. In addition, SW Gas should increase its capability to monitor hourly gas flows for these customers⁶⁵ and allocate EPNG penalties

⁶³ One example emerges from the \$2.1MM of penalties incurred by SW Gas on November 30, 2006 as a result of the force majeure event. Approximately \$121,000, or six percent, of these penalties were the result of actions by transportation only customers. See Larry Black memorandum dated January 30, 2007.

⁶⁴ See ACC Docket No. G-01551A-06-0746 Decision No. 69668.

⁶⁵ There likely will be cost-benefit tradeoffs for some of these customers, as the cost to monitor their gas flows may exceed the benefit of tracking them. This is a judgment call that should be left up to SW Gas management.

resulting from any variance in gas flows caused by these customers. This type of compliance enforcement likely will be an irritant to some transportation only customers,⁶⁶ but under the new EPNG tariff it has become a necessity – otherwise the remaining SW Gas customers will be unfairly charged for the actions of others.

While SW Gas has accomplished some of the above items for some transportation only customers, in the future it needs to push forward for 100 percent compliance of the above items. It is realized this more aggressive compliance approach likely will cause some transportation only customers to return to being regular SW Gas customers, as there is considerable effort required on their part to be fully responsible for all aspects of gas supply, except for the final transportation element on a LDC.

⁶⁶ In hindsight some of these transportation only customers may have, in essence, received a free ride with respect to obtaining their own gas supplies, because of the lack of enforcement by SW Gas. The transition for these types of transportation only customers may be very difficult and potentially costly.

3

GAS PROCUREMENT

Overview

This section of the report examines:

- (1) Southwest Gas' gas procurement strategies and conclusions about their effectiveness,
- (2) the resulting gas prices and their prudence,
- (3) Southwest's internal procurement policies and procedures along with a number of management recommendations for improvement,
- (4) an audit of the quantities and volumes of the Monthly Bank Balance Statements versus the GTS¹ amounts, and
- (5) an audit of selected transactions vis-à-vis Southwest Gas' policies and procedures along with a number of management recommendations.

One of EVA's core analysis methodologies was based on a bottom-up evaluation of the transaction data of the GTS system. GTS breaks out each and every unique supplier contract at the daily level of the audit period (totaling more than 19,300 line items) for volumes scheduled by Southwest's gas buyers. Many of the exhibits include the subtitle, "Based on Audit of Transaction Data", and subsequently this refers to EVA's analyses of the GTS database.

¹ Gas Transaction System is Southwest Gas' internal deal capture system.

In addition, Southwest's internal documents were reviewed. Onsite meetings occurred over three days in mid-January 2008 including monitoring of the next-day gas acquisition, nominating and scheduling processes on El Paso Pipeline, as well as various follow-up teleconference calls and further data requests. The selection of specific transactions that were audited is discussed in that final section. EVA conclusions and recommendations are summarized in the Executive Summary.

Gas Supply Strategy

EVA believes that Southwest Gas' gas supply strategies were prudent and reasonable during the audit period covering September 2004 through April 2007. The key elements of Southwest Gas' portfolio supply strategy have essentially remained the same since the testimony of William Gehlen to the Arizona Corporation Commission (ACC) on July 26, 2005 covering the period September 2003 through August 2004, and as described in a report by Ralph E. Miller submitted by Southwest Gas to the ACC in July 2006. The three key elements of Southwest Gas' supply strategy can be summarized as:

- **Arizona Price Stability Purchases (APSP):** The APSP is baseload fixed priced gas purchased in the months proceeding the November through March high demand season. Southwest Gas attempts to meet 100% of expected minimum load for next winter with this type of gas and about 50% of total annual supply. The objectives of the APSP are to pay more for firmness of supply and stability of price. The audit found that APSP gas was purchased from 3 to 23 months forward² of the physical flow month. The majority of gas is purchased from two San Juan Basin receipt points – Bondad Station and Blanco – since San Juan in theory tends to be lower priced than Permian.
- **Index, or Term, Purchases:** This element of the gas supply portfolio stands ready to meet variable and unpredictable load. It is also mostly firm supply with swing volumes and prices that float on published indices to be used for peaking demand. Supply is diversified by adding delivery receipt points at Permian Keystone and finally at Waha (being the most expensive traditionally). Southwest Gas models warm, normal, and cold temperature scenarios for the load forecast and includes scenarios that prepare for the all-time peaks.
- **Spot and Interruptible Purchases:** This element includes spot purchases for the next day or short time windows and includes interruptible gas that is relied heavily upon during the summer months. The summer months are the lowest demand season for Southwest's customers and there is high probability that the interruptible gas will not be cut during the summer. Also if interrupted during the summer, replacement supply is typically easily available from the marketplace.

² More discussion of this practice follows in the Policies and Procedures section

Exhibit 3-1 summarizes Southwest's use of the three supply elements during the entire audit period. Southwest did follow gas supply strategies that were similar to both its intended strategies and to past strategies, as stated in various Southwest documents submitted to the Commission. The total scheduled volumes of 173,696,102 mmBtu were based about 58% on fixed price supply, about 20% on floating index price supply, and 22.5% on spot/interruptible purchases over the entire audit period. The resulting value of \$1,132,941,000 was about 58% on fixed price supply, about 21% on floating index price supply, and more than 21% on spot supply. Southwest gas supplied and diversified its gas portfolio from the potentially least expensive gas receipt points with 88% of the volume from the San Juan Basin, 8% of supply from the Permian Basin, and 4% from Waha.

**Exhibit 3-1. Summary Of Gas Supply Portfolio, September 2004-April 2007
(Based on Audit of Transaction Data)**

Portfolio Element	Fixed	Index	Spot	Total
Volume (mmBtu)	100,117,753	34,420,378	39,157,971	173,696,102
	57.6%	19.8%	22.5%	100.0%
Value ('000)	\$ 652,443	\$ 234,581	\$ 245,917	\$ 1,132,941
	57.6%	20.7%	21.7%	100.0%
Receipt Point	San Juan	Permian	Waha	Total
Volume (mmBtu)	152,644,841	14,040,650	7,010,611	173,696,102
	87.9%	8.1%	4.0%	100.0%
Value ('000)	\$ 983,531	\$ 91,504	\$ 57,906	\$ 1,132,941
	86.8%	8.1%	5.1%	100.0%

Southwest's heavy reliance on the APSP as the largest component of its portfolio supply strategy appears prudent to compensate for its lack of access to storage capacity, a critical tool that most LDCs use to manage volatility and meet seasonal demand. Market-area storage is the key infrastructure component that achieves balancing between sudden load and pipeline flow changes, and other exogenous events such as pipeline problems or supply force majeure. While there is a wide range of practices among utilities, one study showed that U.S. LDCs purchase forward baseload supply to meet some 60-80% of their current year load requirements and also use forward supply to meet between 15-30% of their next year's requirement.³ SWG's policies prohibiting

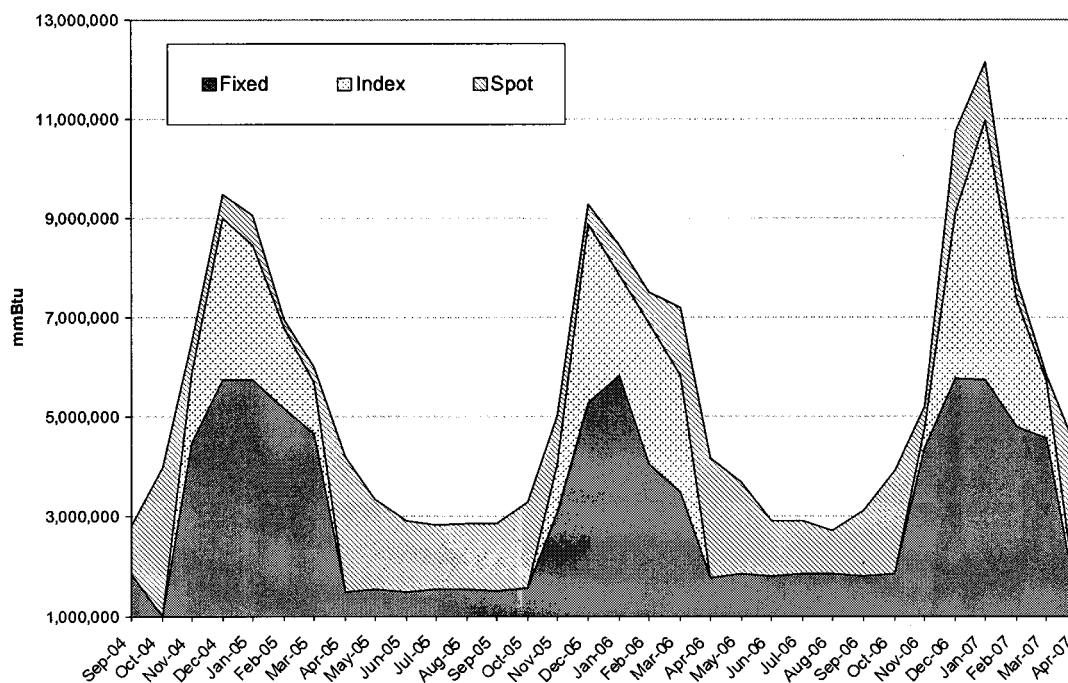
³ National Rural Electric Cooperative Association, 2002. *Strategic Fuel Supply Guide*, Project 01-39.

the outright sale of excess gas to third parties also prevents any greater reliance on the fixed price baseload element.

Southwest's use of the other two supply elements is an attempt to diversify its supply portfolio sufficiently with inverse characteristics than the firm baseload characteristics. The term or index purchases are essentially options that give SWG the right but not the obligation to call on firm gas supply for a very small premium over index of up to several cents per mmBtu. Likewise the use of spot gas and interruptible gas helps Southwest diversify its supply portfolio with elements that can be tapped when the economics are attractive. These three elements appear to have served SW Gas well to meet its commitment to serve its regulatory load.

Exhibit 3-2 shows the results of SW Gas' supply strategy during the audit period as actual purchases by supply element varied seasonally and monthly. APSP fixed price supply varied from 47 to 84% of the total during the winter months of November through March, and fell to 28 to 67% of the total portfolio during the shoulder and summer

**Exhibit 3-2. Composition Of Gas Supply Portfolio
(Based on Audit of Transaction Data)**



months of April through October. Index gas was purchased only during November through March satisfying 8 to 43% of monthly winter needs. The spot element, that includes interruptible purchases, was relied upon in all months of the year and ranged from 2% to 20% of the total during November through March, versus 32 to 75% of the total during April through October.

Analysis between calendar years, or SW Gas' conventional gas years from November through October, is somewhat limited because the audit period contains only two complete calendar years or SW Gas years (November-October), three complete winters, and two complete summers. Therefore EVA comparisons are limited to between the seasons and between the months throughout the audit period.

Exhibit 3-3 compares the three winters of the audit period. Load increased substantially during the 2006/07 winter to its highest level of the audit period, suggesting cool temperatures, and conversely warm temperatures in 2005/06. Simple averages across the five winter months show inherent variability between years due to weather and also reflect management decisions during the planning periods.

**Exhibit 3-3. Composition Of Supply Portfolio During Winter Seasons
(Based on Audit of Transaction Data)**

Winter	Nov-Mar Volume (mmBtu)	Simple Average of Winter Months		
		Fixed	Index	Spot
2004/05	38,005,857	69%	25%	6%
2005/06	37,446,825	58%	30%	12%
2006/07	41,606,209	65%	27%	8%

Variations occur in the composition of the supply portfolio at the monthly level. During the core summer months, the contribution of spot and interruptible gas holds fairly steady, in the absence of winter heating load. The contribution of baseload gas to the core summer months, June-August, is also fairly steady. Sharper differences emerge between the winter months that are driven largely by the divergences of actual heating degree days from normal heating degree days. As an example, in November 2006 the contribution of fixed price baseload gas was unusually high at 84% of total requirements

but contributed only 47% of total requirements in January 2007. Exhibit 3-4 shows heating degree days for Phoenix for the first three months of the 2006/2007 winter. The heating degree day data shows that November 2006 was fairly warm at only 37% of normal heating degree days, whereas January 2007 was 13% colder than normal for Phoenix.⁴

Exhibit 3-4. Heating Degree Days For Phoenix, AZ

	Normal	Actual	% of Norm
Nov-06	129	48	37%
Dec-06	318	322	101%
Jan-07	322	363	113%

Source: NOAA/NWS

Exhibit 3-5 shows the detail of the supply portfolio at the monthly level. Such variation between winter months also testifies to the difficulty of matching baseload supply to a load forecast produced some four to six months earlier, and in absence of a full requirements contract. The largest load swing variation between the 32 months of the audit period is measured between August 2006 and January 2007 from 4,151,768 to 12,139,138 mmBtu, a swing of 9,423,624 mmBtu or almost 4.5 times. This difference from low to high also represents 15% of annual 2006 consumption of 62,438,087 mmBtu.

Day-to-day variability can also be severe. Late November and early December 2006 are of particular interest due to the supplier force majeure events resulting from the gas production well freeze-offs, as discussed in Chapter 2. On November 30, 2006, SW Gas load spiked upward by some 238,440 mmBtu to 488,395 mmBtu⁵ when compared to the prior day's scheduled volume (including the load forecasting shortfall/error of some 108,000 mmBtu). Transactional data in GTS, and summarized in Exhibit 3-6, show that for November 30, total scheduled gas to Southwest increased by 56,458 mmBtu versus the prior day, based on scheduled baseload supply falling 19,696 mmBtu, scheduled swing gas rising 61,927 mmBtu, and scheduled spot gas rising 14,227 mmBtu (for Cycles 1 through 4). These numbers above suggest that higher pipeline receipts only

⁴ Phoenix was chosen as an example since it represents about 80% of Southwest's jurisdictional load in Arizona.

⁵ January 30, 2007 memo of Larry Black estimates November 30 load at 488,395 mmBtu and is compared to GTS scheduled volume of 249,955 mmBtu, hence EVA's phraseology for the daily load swing of "some".

**Exhibit 3-5. Monthly Detail Of Supply Portfolio
(Based on Audit of Transaction Data)**

Date	Total Value (\$1000s)	Total Volume (mmBtu)	Composition of Volume		
			Fixed	Index	Spot
Sep-04	\$ 11,878	2,794,397	66.2%	0.0%	33.8%
Oct-04	\$ 19,225	3,966,930	24.8%	0.0%	75.2%
Nov-04	\$ 35,964	6,512,148	68.9%	21.4%	9.7%
Dec-04	\$ 53,890	9,466,109	60.6%	34.5%	4.9%
Jan-05	\$ 49,209	9,058,663	63.3%	30.1%	6.6%
Feb-05	\$ 37,792	6,972,344	74.1%	23.4%	2.5%
Mar-05	\$ 32,773	5,996,593	77.5%	17.2%	5.3%
Apr-05	\$ 24,989	4,181,213	35.6%	0.0%	64.4%
May-05	\$ 19,064	3,340,168	46.2%	0.0%	53.8%
Jun-05	\$ 16,054	2,896,834	51.3%	0.0%	48.7%
Jul-05	\$ 15,918	2,808,974	54.9%	0.0%	45.1%
Aug-05	\$ 18,306	2,860,500	54.1%	0.0%	45.9%
Sep-05	\$ 19,424	2,856,089	52.5%	0.0%	47.5%
Oct-05	\$ 25,278	3,289,504	47.1%	0.0%	52.9%
Nov-05	\$ 38,925	5,020,676	61.2%	19.3%	19.6%
Dec-05	\$ 76,480	9,273,958	57.0%	38.7%	4.4%
Jan-06	\$ 58,632	8,456,092	68.7%	24.0%	7.4%
Feb-06	\$ 48,497	7,494,424	54.2%	37.4%	8.4%
Mar-06	\$ 44,373	7,201,675	48.4%	32.3%	19.4%
Apr-06	\$ 24,909	4,151,768	42.6%	0.0%	57.4%
May-06	\$ 21,897	3,666,643	50.4%	0.0%	49.6%
Jun-06	\$ 17,021	2,899,208	62.1%	0.0%	37.9%
Jul-06	\$ 17,410	2,909,847	63.2%	0.0%	36.8%
Aug-06	\$ 17,387	2,715,514	67.8%	0.0%	32.2%
Sep-06	\$ 18,460	3,109,089	57.9%	0.0%	42.1%
Oct-06	\$ 21,034	3,919,284	47.5%	0.0%	52.5%
Nov-06	\$ 42,193	5,186,157	84.3%	7.7%	8.0%
Dec-06	\$ 80,570	10,728,386	53.7%	31.2%	15.0%
Jan-07	\$ 88,176	12,139,138	47.1%	43.1%	9.8%
Feb-07	\$ 61,292	7,745,092	62.0%	32.7%	5.3%
Mar-07	\$ 46,427	5,807,436	78.4%	19.8%	1.9%
Apr-07	\$ 29,493	4,271,249	27.9%	0.0%	72.1%

met 24% of Southwest's day-to-day load spike⁶ despite nominations that totaled some 417,000 mmBtu during Cycles 1-4 for November 30⁷. One fortunate factor for SW Gas is that this event occurred on the last day of November, with higher amounts of baseload gas scheduled to kick-in on day two of the event since the new gas month of December had significantly higher volumes of planned baseload gas. El Paso allows its shippers to

⁶ Versus the prior day, this November 30th calculation assumes increased scheduled volume of 56,458 mmBtu against increased load of 238,440 mmBtu.

⁷ Internal memo of Larry Black from January 30, 2007. This memo also states that Southwest increased its total nominated volumes for Cycle 3 by 50,000 mmBtu and by for Cycle 4 by 70,000 mmBtu. GTS only shows scheduled, not nominated or actual received volumes.

make-up the previous month's shortfall during the first ten days of the next month, and Southwest attempted to minimize November's shortfall as seen by the higher scheduled volumes through December 4.

**Exhibit 3-6. Scheduled Gas Supply During The 2006 Force Majeure Event
(Based on Audit of Transaction Data, mmBtu)**

Flow Date	Volume	Fixed	Index	Spot
11/28/2006	204,564	146,880	10,000	47,684
11/29/2006	249,955	146,570	30,000	73,385
11/30/2006	306,413	126,874	91,927	87,612
12/1/2006	291,744	175,855	38,635	77,254
12/2/2006	365,992	181,350	39,220	145,422
12/3/2006	379,306	181,734	39,741	157,831
12/4/2006	421,932	183,325	19,501	219,106

Gas Pricing

SW Gas' procurement strategies were effective at providing price stability - one of the two main objectives of the Arizona Price Stabilization Plan. EVA also concluded, based on the analysis of all of SW Gas' natural gas supply transactions during the audit period September 2004 through April 2007, that transactions executed and prices paid were reasonable and prudent. Exhibit 3-7 shows that SW Gas' procurement strategies produced a mean average cost of gas that was similar to the market price of gas, when measured against the entire audit period.

**Exhibit 3-7. Summary Of Prices, September 2004-April 2007
(Based on Audit of Transaction Data)
\$/mmBtu**

	Mean	Std. Dev.	Max	Min
Southwest Gas Portfolio	6.35	1.02	8.25	4.25
San Juan - Daily Index	6.38	1.47	10.90	4.26
Permian - Daily Index	6.59	1.55	11.03	4.35
Waha - Daily Index	6.65	1.49	10.92	4.53
San Juan - FOM Index	6.26	1.49	10.82	3.43
Permian - FOM Index	6.44	1.47	10.75	3.57

Source: Platts Inside FERC's Gas Market Report for daily and first of month indexes.

The similarity of Southwest's price to market price, within pennies when measured over the entire period, is a result of their supply strategies discussed above. Also, SW Gas' diversity to a large number of suppliers also helps ensure access to competitive prices. The APSP element provided price protection to SW Gas customers during the strong natural gas rally of 2004 and 2005, while the index and spot/interruptible elements were priced closer to prevailing market values as seen in Exhibit 3-8. In addition to meeting highly variable loads, the index and spot gas also benefited consumers as gas market prices dropped. Because their contract values are based on floating monthly or daily price indices, or bilateral daily transactions, their prices are naturally close to market, and hence allowed Southwest customers to participate as the market price declined in 2006 and 2007. Exhibit 3-8 also shows that Southwest's full portfolio price during any one month will typically lie between the lagging fixed element and the floating prices of the index and spot elements. As expected, the fixed price element of the portfolio was very low in the first half of the audit period as market prices climbed, and then continued to climb in the second half of the audit period keeping the fixed price element high until all of the \$8 to \$11/mmBtu gas was able to roll off, up to some 23 months after index prices peaked.

**Exhibit 3-8. Average Weighted Monthly Prices By Portfolio Element
(Based on Audit of Transaction Data)**

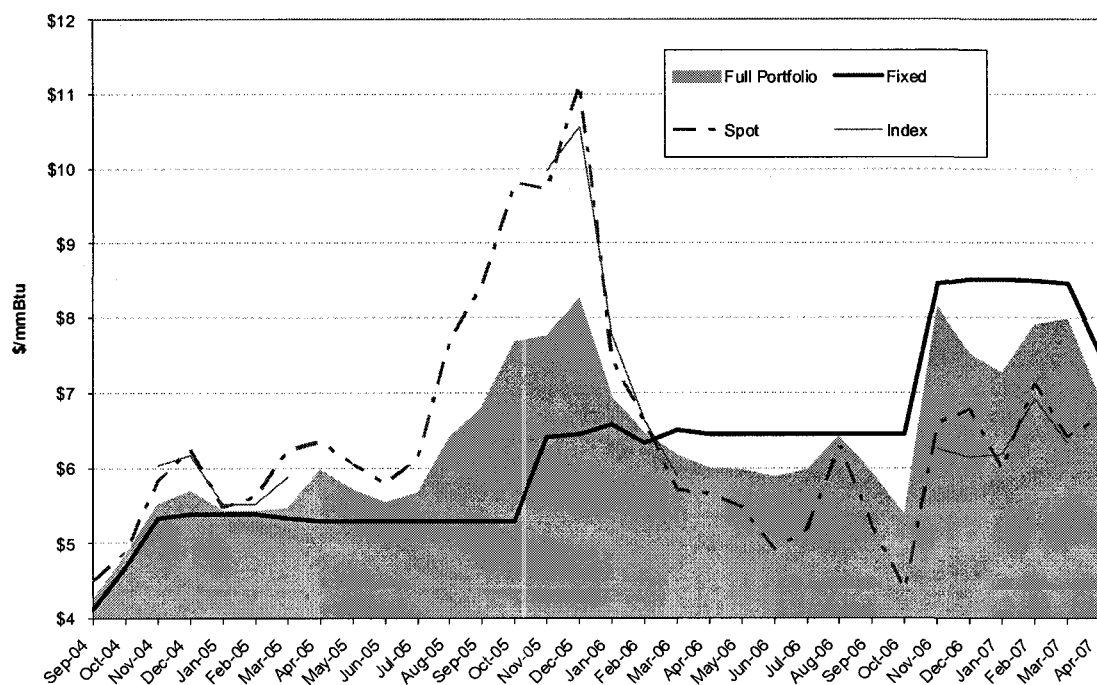
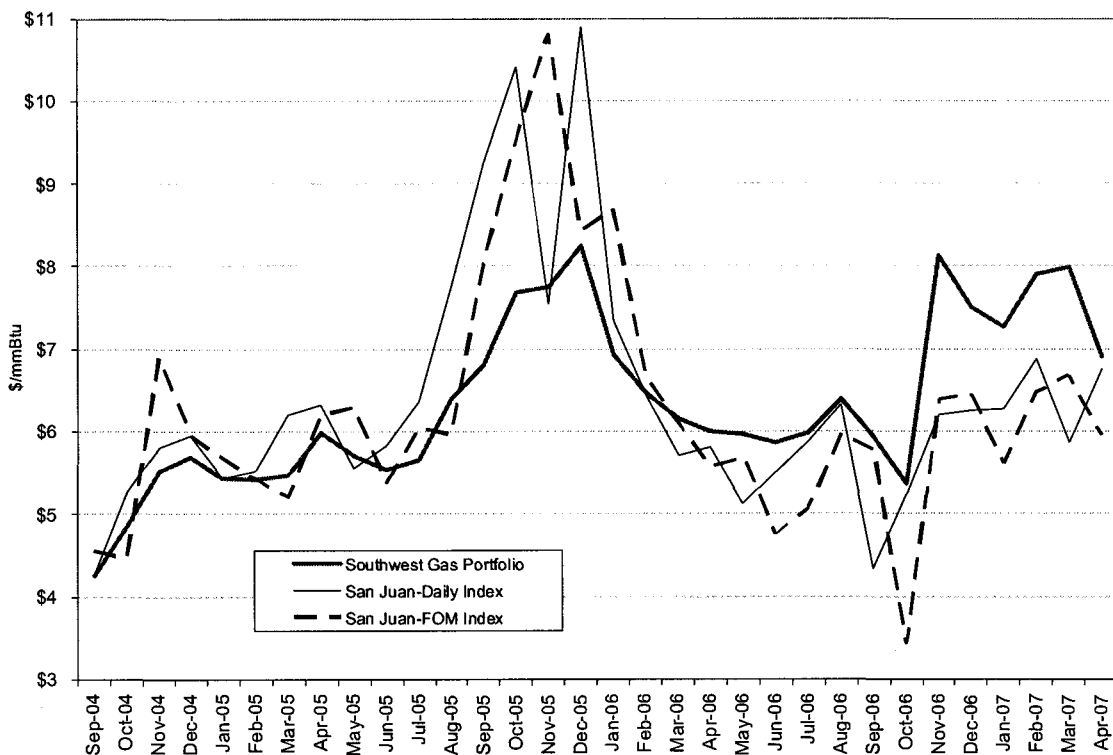


Exhibit 3-9 compares the average monthly values of Southwest's full portfolio to the published San Juan indices for first of month settlement (resulting from bid week) and to daily settlement during the audit period. For this illustration, San Juan was selected since it represented 88% of the total gas volume during the audit period. As expected and consistent with the above discussion about supply strategy, Southwest's weighted price was below or near market indices during the first half of the audit period. (Note: The other 12% typically based on Permian and Waha receipt points would have a tendency to pull up the SW Gas price versus the San Juan price.) Also as expected, Southwest's weighted price was higher than the San Juan price indices during the second half of the audit period.

**Exhibit 3-9. Price Comparison
(Based on Audit of Transaction Data)**



SW Gas' procurement strategies were also effective at reducing price volatility — the second main objective of the Arizona Price Stabilization Plan. Exhibit 3-7 referenced formerly, shows that SW Gas achieved a significantly smaller standard deviation around

the mean average price when compared to market indices during the audit period. One standard deviation measures \$1.02/mmBtu for the Southwest portfolio, compared to \$1.47-\$1.55/mmBtu for the published market indices. This is a significant reduction in volatility of 30-31%, as measured by standard deviation. Exhibit 3-10 shows the seasonal price deviations compared to the mean average price of the audit period. As expected, winters tend to be above the mean average price of the portfolio, while summers and shoulder months tend to fall below the mean average price of the portfolio.

**Exhibit 3-10. Monthly Price Change From Mean Average Price
(Based on Audit of Transaction Data)**

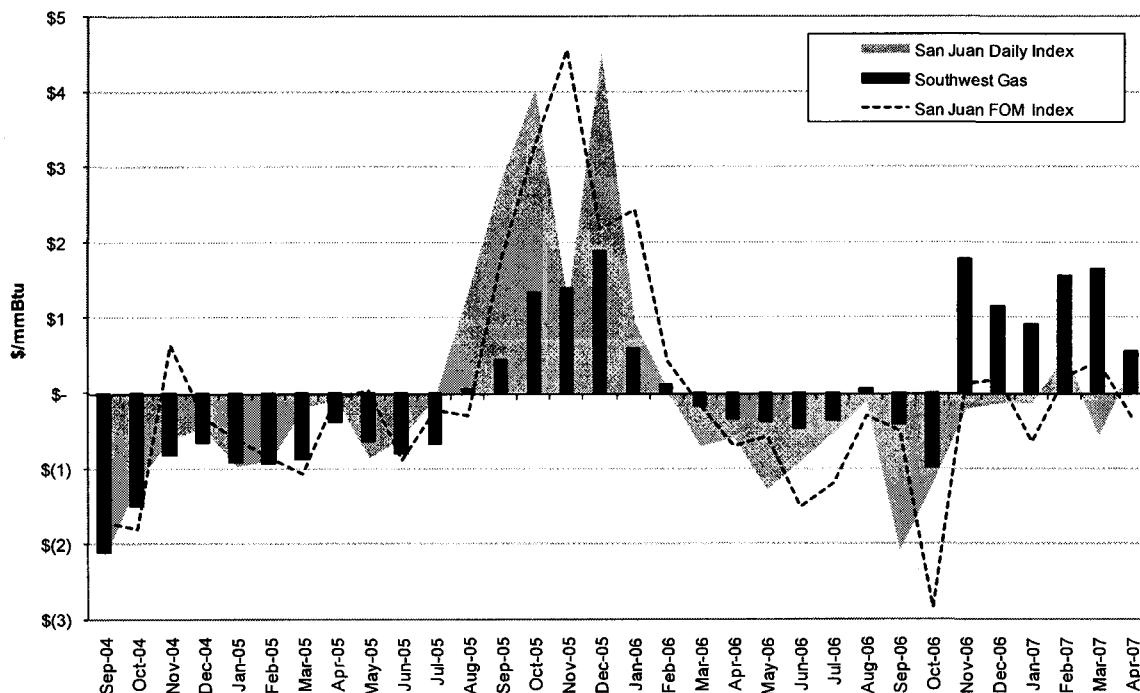
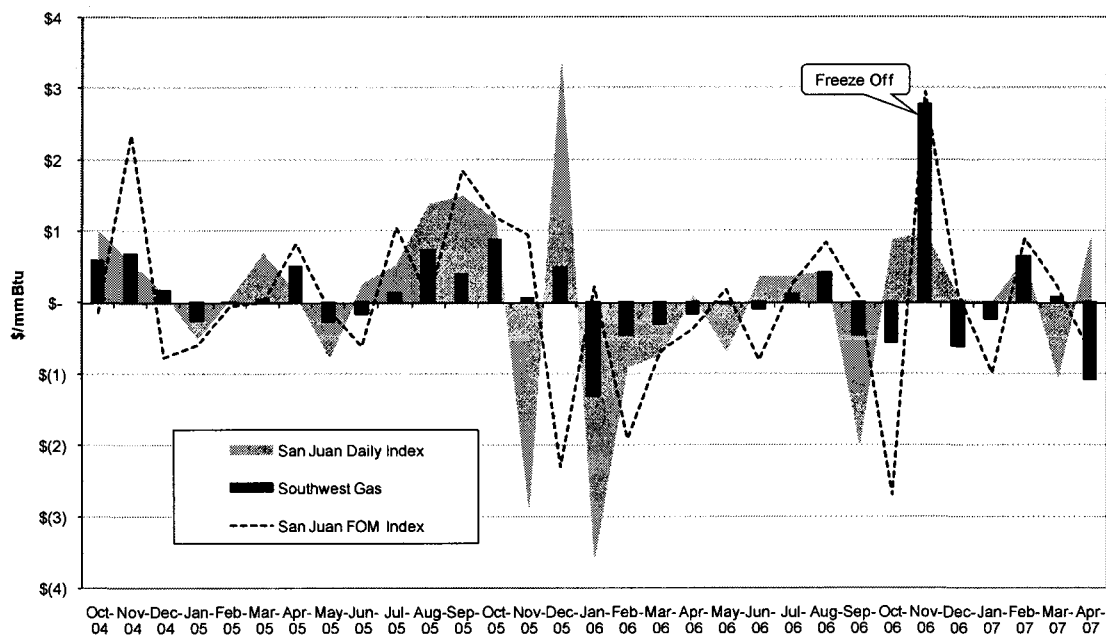


Exhibit 3-11 also shows the monthly change in price compared to the prior month. In almost all cases, Southwest's results shows lower price volatility compared to the market price indices.

The price indices used by SW Gas in setting their natural gas purchase prices are standard industry indexes with good market liquidity. The published price indexes used in SW Gas transactions are believed to be limited to:

- Gas Daily, El Paso San Juan Basin
- Gas Daily, El Paso Permian
- Gas Daily, El Paso Bondad
- Gas Daily, Waha
- Inside FERC, First of Month, El Paso San Juan Basin
- Inside FERC, First of Month, El Paso Permian

**Exhibit 3-11. Monthly Price Change From Prior Month
(Based on Audit of Transaction Data)**



Exhibits 3-12 and 3-13 illustrate the number of discrete transactions and the related underlying volume of gas tracked during bid week and used by *Platt's Inside FERC Gas Market Report* to set its First of Month published price indices for the San Juan Basin and Permian Basin. A substantial analysis of market liquidity might be required if SW Gas was going to accept an index price for all, or a larger percentage, of its gas supply portfolio.

Exhibit 3-12. Volume Of Bid Week Gas Included In Published FOM Indices

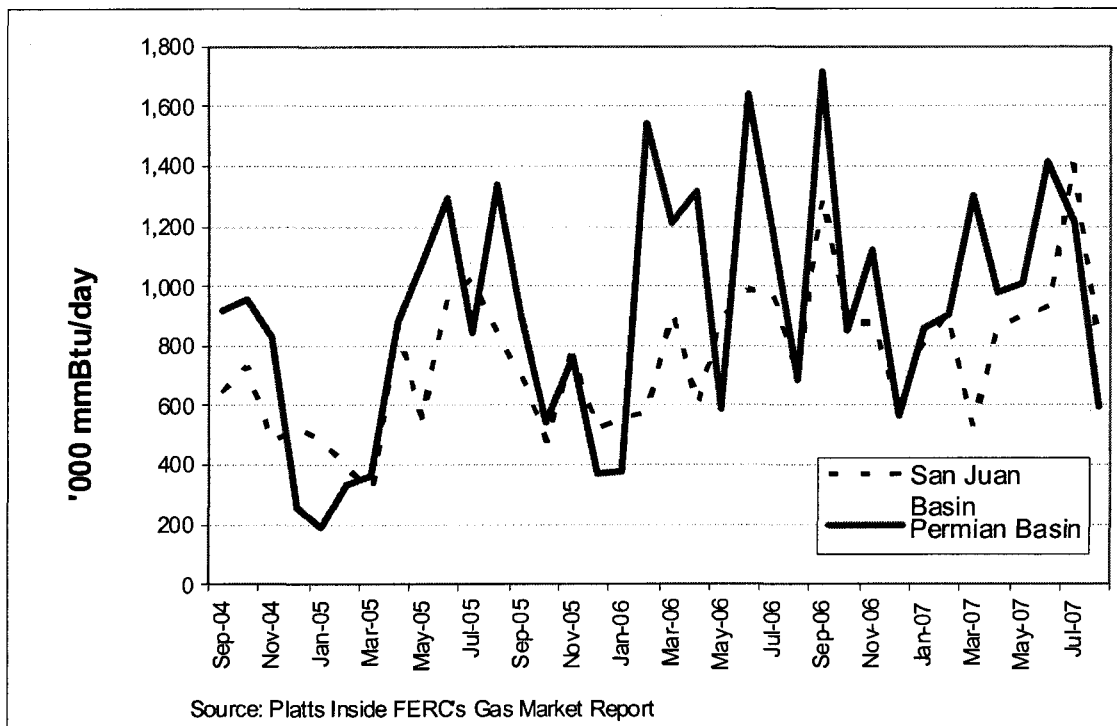
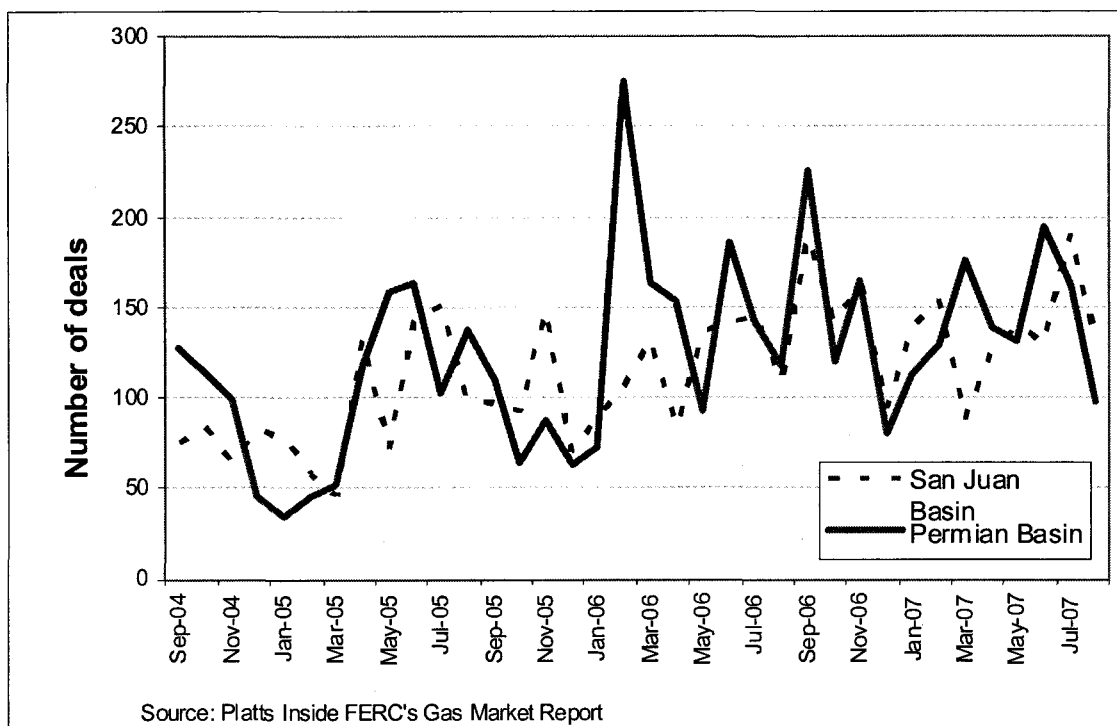


Exhibit 3-13. Number Of Deals Included In Published FOM Indices



Platt's Inside FERC Gas Market Report and *Gas Daily* are bellwether industry publications and many U.S. physical transactions are based upon them. The cash indices mentioned above, as well as most U.S. natural gas cash pricing, are to some degree influenced by NYMEX prices, regardless of whether one is directly participating in NYMEX markets or not. The starting point for virtually all U.S. gas pricing is the NYMEX Henry Hub delivery location (and all related look-a-like OTC markets such as ICE).⁸ Virtually all U.S. prices are composed of NYMEX Henry Hub, plus or minus a basis price differential. Forward price curves are built off this concept as well. Because of this phenomenon, market participants constantly watch changes in the NYMEX Henry Hub values which tend to inform and influence their decisions about the market fundamentals and the general state of participation by the different types of market participants (for instance, speculators versus hedgers).

SW Gas' internal policies allow it to transact fixed priced gas at either one single value or in two separate components, NYMEX and basis to be locked at different times. EVA's opinion is that because the NYMEX component is already embedded (directly and indirectly) into a company's gas purchases, it is sometimes best to assert control over that pricing component if trying to meet a specific objective, rather than to be at the whim of market forces. Stated in other words, EVA is not concerned that SW Gas may rely on NYMEX based pricing, as this is the leading price benchmark of the U.S. industry, and it cannot be avoided. NYMEX prices indirectly influence all gas prices, thus having the option of control over it, is preferable, to having no control.

Manipulation of U.S. published gas market price indices and manipulation of gas markets has been under intense scrutiny, particularly from activities of 2000 through 2006. Some of the more notable cases have involved companies such as Amaranth and El Paso Energy. The relevant contracts involved some of the most liquid price indices in the natural gas industry, including NYMEX and ICE contracts based on a liquid Henry Hub reference delivery point. While such events may be characterized as unfortunate, the silver lining, if any, is that today there is greater market oversight and enforcement of the natural gas markets by both the FERC and the CFTC. It is EVA's belief that this stepped up enforcement will help to minimize potential future abuse of natural gas

⁸ Intercontinental Exchange

markets and pricing indices. Many gas utilities and other industry participants are price takers and need to rely on published indices as representations of competitive commodity markets. It is in the best interest of all participants for all pricing points to have reliable and valid published price indices.

In reality, any of the published price indices can be subject to potential abuse if an individual, or set of individuals, are intent on pursuing an unfair advantage in the marketplace. Theoretically, higher liquidity (greater number of transactions reported, higher volume coverage, and participation by a larger number of companies), helps protect price indices against potential market manipulation. An annual review by SW Gas of its counterparties may indirectly help to address some of this concern, along with monitoring of and vigilance over the liquidity of the price indices it uses.

A final and controversial subject is the potential requirement to report transactions and deal information to industry publications for inclusion in published price indexes. As stated previously, EVA believes that is to the benefit of all market participants (including utility rate payers) to have reliable and valid published indices based on truly competitive market forces. To EVA's knowledge, SW Gas currently does not report pricing information to industry publications. Contributing their specific company information would increase liquidity for the indices that concern SW Gas and be likely to have the impact of increasing the reliability of the published indices. The desired ideal standard is for all companies to participate to create a highly competitive marketplace.

However EVA also strongly feels that each company must be responsible to determine its own comfort level and ascertain its risks and rewards before participating in the sharing of its confidential information. Participation is not a trivial matter in today's litigious world.

If SW Gas decided to participate, it would need to ensure that its associated processes were sufficiently well-designed to the minimize risks associated with this process. One of the recommended requirements would be to create complete independence between the personnel and functions that report deals to publications from the personnel and functions that procure gas. For instance reporting could be done from the Accounting Department or Risk Management Department. It should be noted there is an associated

administrative burden and cost to such reporting. Southwest's current *Code of Business Conduct & Ethics* require that "media inquiries must be referred to the Corporate or Division Communications Departments." There is also a potential conflict of interest if any 'trading' occurs inside a utility procurement shop, which is not the case for SW Gas. Likewise if gas buyers' bonuses are based on beating published indices (and buyers are responsible to also report data to publications), incentives to 'distort' reality could exist. All of the positions in Southwest's gas purchasing and transportation department were reported as 'salary only' positions.⁹

There are other complexities to consider on this topic. For instance, the 50% of so of the total volume that Southwest purchases for the APSP program does not have a natural publication to report into, since these are purchases made in the forward markets, out one to two years in the future, and are classified as over-the-counter deals that are more illiquid the farther one goes into the future. The trade publications discussed above tend to focus on next month (bid week) and next day (daily) markets. The most popular electronic venue that reports the more illiquid over-the-counter deals is the ICE. SW Gas participates on the ICE, particularly for its spot gas purchases for next day and next month. The ICE has the benefit of increasing workplace efficiency regarding price discovery and facilitating quick execution of transactions, with high liquidity for the short term markets. It is an essential tool for today's gas buyers. One primary question is whether SW Gas would report 100% of its transactions, or only those transactions that have relevance to the daily and monthly index publications.

If the ACC decided to require Arizona regulated gas utilities to participate in the reporting of transaction data to publications, for fairness reasons and to level the playing field, it would be important to also require regulated electric utilities to report as well. Unilaterally ordering gas utilities to report could be discriminatory. Any decision by the ACC to report could also have unintended consequences, and thus would need to be carefully examined before mandating participation.

Policies And Procedures

EVA found that many of SW Gas company policies, procedures, and strategies are insufficiently documented in official company documents. While the concepts embedded

⁹ EVA email discussions with senior management of Southwest Gas dated March 4, 2007.

in SW Gas' policies, procedures, and strategies appear reasonable and prudent, curiously one must tend to go to the documents submitted by SW Gas to the Arizona Corporation Commission to find the most complete picture of company policies, procedures, and strategies. In addition, some policies, procedures, and strategies fall short in certain areas by their lack of documented official position on certain subjects.

Best Practices require that policies and procedures are contained in, say, one or two company documents with sufficient detail such that new employees could read and immediately perform the bulk of their work. The *Annual Gas Procurement Plan (Section A)* submitted in December of each year to the ACC is probably the most comprehensive discussion of Southwest's gas supply policy, outside of external consultant's reports.¹⁰ However, only *one* paragraph (the first paragraph) discusses SW Gas' supply strategy. The remainder of the Section A (another 4.5 pages) discusses SW Gas' acquisition procedures. Another good discussion of Southwest procedures is found in *Department and Staff Responsibilities, Portfolio Selection Procedures*¹¹ originally created for submission to the ACC. While containing valuable information, these documents still fall short in several areas as noted under the recommendations. These recommendations take on elevated importance and urgency given SW Gas's expected execution of its first-ever financial derivative hedge in 2008. (It should be noted that EVA did not review any of the policies and procedures associated with financial derivative hedging.)

EVA recommends that Southwest clarify all company policies and procedures in internal company documents to be reviewed, at least annually, for use by both employees and decision makers. Company employees should acknowledge acceptance by signing the policies each year. EVA's recommendation is to supplement current policies and include discussion on the following types of topics:

1. Consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.
2. Clarify the APSP supply element by documenting required timing and volumes for the next one or two years forward. This is important because these are long-term fixed price purchases that have repercussions to the gas supply portfolio for several years. The 2007 Arizona Annual Gas Procurement Plan submitted to the

¹⁰ 2004 through 2007 versions were reviewed

¹¹ Docket No. G-01551A-07-0504, Data Request STF 4.25.

ACC contains the most detail description of the APSP such that "Southwest conducts solicitations from November through August every three to six weeks" ... "for the upcoming portfolio year and up to one year beyond that year" ... "and may include bid requests for one or more of the three portfolio years." Senior management noted that this element was intended to be "programmatic," yet there is no calendar showing potential dates or quantities to be purchased in the year or quarter ahead. Verbally Southwest explained that its intention was to purchase about 40% of the next year's supply in the twelve months preceding physical flow, and another 10% in the two years preceding physical flow for a total of about 50%. That would be about 2% to 5% in each transaction, with some 4 transactions during the thirteen to twenty-four months before physical flow and another 10 purchases made during the last 12 months before physical flow. Truly successful dollar cost averaging relies on programmatic dates and volumes that are known and planned. Some companies have found the use of living appendices (to the annual company policies) helpful to update forward time windows and volume ranges that may change frequently. If there is uncertainty, then windows of time and ranges of volume or duration can be established instead. This approach also has the benefit of allowing a record of results and allows documentation of reasons for any deviation from the plan which in the long run improves the quality of the internal and external audit trail(s) and makes it easier for a company to assert and prove that their hedging programs have been prudent.

3. During the onsite interviews of mid-January 2008, it was noted that lately much of the APSP gas was entirely fixed at the time of initial purchase, that is, no price components were left floating to be locked-down at a later date. SW Gas policies allow management to use their judgment on this issue. EVA agrees that this preference is best left to the judgment of SW Gas management and their experts. Still EVA has several comments about this topic.
 - a) If SW Gas uses its best judgment, to be certain, there will be outcomes that "win" some years and other outcomes that "lose" in other years. One's best judgment is not always correct, and thus, should not be expected to always be correct.
 - b) A truly programmatic hedge involves always being a price taker (without reserving judgment) over a relatively long stretch of time that allows dollar cost averaging to occur effectively.
 - c) A hybrid of the two above strategies is acceptable, but the precise strategy should be recognized and declared in company policies and procedures to guide employees and decision makers, as well as the ACC's oversight.
4. On a daily basis, transactions executed by Southwest gas buyers bind the company as they purchase gas from various suppliers. During interviews, Southwest management explained that prior to each flow month, the Supply Planning Department provides gas buyers with a monthly plan, *Arizona Dispatch Guidelines*, that outlines all firm purchase contracts sorted in order of economic dispatch to be utilized for the upcoming flow month. These documents were viewed by EVA. In EVA's view, this document basically acts as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement.

It is a sound process, however no mention of this document or process was found in any company policy or procedure. This process should be included in the description of the buyers' formal procedures.

5. During interviews, it was noted out that SW Gas has a company policy of never selling excess gas to third parties, for various regulatory and legal reasons that have roots in both FERC, as well as FAS, regulations due to potential negative repercussions as perceived by the company. However it is impossible for any LDC to perfectly predict load for each day and every hour. Additionally since SW Gas has no storage capacity to flow its excess gas and because it potentially faces high El Paso Pipeline charges and/or penalties for pipeline imbalances, SW Gas needs to have an internal mechanism to balance its occasional excess gas. SW Gas uses the concept of 'unbuying' to help optimize its portfolio and minimize cost. In such circumstances, a SW Gas buyer instructs the original supplier of the gas not to deliver gas that it had previously purchased, and to charge SW Gas accordingly. Such 'unbuying' transactions, or turning back of gas, then lead to liquidated damages per contract terms (some true-up or true-down to current market between SW Gas and the supplier) and possibly a small additional or negotiated charge. 'Un-buying' practices may have accounting repercussions where SW Gas must mark-to-market any 'un-bought' gas if it was originally based on firm fixed priced contracts. For this reason, SW Gas has a policy of turning back index priced gas first, and second turning back fixed priced gas, if necessary. These company policies, as well as the reasons for the policies, should be reevaluated, and then explicitly documented in official company policies and procedures.

Comparison Of Monthly Bank Balance Statements And GTS

For gas commodity charges, a comparison was made between all GTS transactions and the Monthly Bank Balance Statements filed with the ACC. Exhibit 3-14 tabulates the differences for monthly volumes and values. The monthly difference is expressed as Monthly Bank Balance Statement minus the GTS transactional values. The differences can be attributed to items that are not captured in the GTS system: (a) liquidated damages per contract terms, (b) commodity demand charges, (c) balancing cash-outs to/from El Paso Natural Gas Pipeline, (d) gas related to Dacott Industries that delivers on Transwestern, and (e) prior period corrections. A positive difference is read such that SW Gas must pay this additional amount over and above the gas commodity charges captured in the GTS system. A negative difference is a credit.

Exhibit 3-14 Difference Of Monthly Bank Balance Statements Minus GTS Data

	Value	Volume (mmBtu)
Sep-04 \$	12,311	3,433
Oct-04 \$	21,201	4,481
Nov-04 \$	149,709	6,080
Dec-04 \$	146,898	9,633
Jan-05 \$	238,599	9,032
Feb-05 \$	204,543	10,977
Mar-05 \$	255,029	3,365
Apr-05 \$	14,907	2,322
May-05 \$	95,130	1,881
Jun-05 \$	9,073	1,530
Jul-05 \$	7,370	1,467
Aug-05 \$	8,146	1,434
Sep-05 \$	12,976	1,487
Oct-05 \$	45,619	1,848
Nov-05 \$	84,834	3,572
Dec-05 \$	157,205	6,743
Jan-06 \$	166,271	6,290
Feb-06 \$	135,552	4,071
Mar-06 \$	86,944	3,738
Apr-06 \$	74,032	12,563
May-06 \$	9,196	1,803
Jun-06 \$	7,993	1,472
Jul-06 \$	7,104	1,469
Aug-06 \$	21,395	3,201
Sep-06 \$	14,459	3,286
Oct-06 \$	12,474	2,485
Nov-06 \$	234,459	20,822
Dec-06 \$	191,000	6,655
Jan-07 \$	2,036,644	229,081
Feb-07 \$	161,415	4,041
Mar-07 \$	176,385	(1,280)
Apr-07 \$	13,066	2,275

EVA evaluated these differences for reasonableness.¹² Only the differences for January 2007 appeared somewhat extraordinary representing 1.9% of GTS volumes and 2.3% of GTS values. As previously noted, heating degree days for Phoenix during January 2007 were 13% above normal. Southwest's purchased gas expenses were the largest of the audit period for January 2007 at \$90.2 million for load of 12,368,219 mmBtu.

Further analysis of January 2007 showed that 97% of the total volume was due to item (c) above, balancing cash-outs payments made to EPNG. For January 2007, Southwest was forced to pay El Paso 221,845 mmBtu, or \$1.85 million, to bring the gas commodity imbalance down to 5%. EPNG requires monthly imbalances in excess of 5% to be

¹² Of the 32 months, difference was 0.1% for 27 months and 0.2%-0.4% for four months.

cash-out and reduced to the 5% level in the first month of the imbalance, with the remainder rolled forward to the second month when EPNG requires that the imbalance is reduced to 3%, and finally reduced to 0% in the third month of its existence. Each month is tracked separately by EPNG, and prior and next months are not rolled into administration of each current month's requirement.

If load was forecasted correctly, SW Gas would still have had to purchase this gas from a third party supplier. Instead SW Gas was forced to purchase this gas from El Paso, which did charge a premium over market. The average price paid to El Paso is estimated by EVA at \$8.327/mmBtu, compared to the highest Daily or First of Month published market index of \$6.42 (Daily Waha), calculating to a premium of some \$423,054 to bring the imbalance down to 5%.

Several factors should prevent this situation from occurring again. A repeat of such a large cash-out penalty in the future might be very well be viewed as imprudent given SW Gas' climb up the learning curve since the introduction and implementation of El Paso's new tariffs during 2006 and 2007. EVA would expect the following (and subsequent) items to prevent a repeat of such a large cash-out from occurring, particularly:

- a) Proactive improvements to the quality and accuracy of SW Gas' load forecasts.
- b) Changes to treatment of SW Gas T-1 customers.
 - o Changes to SW Gas's tariff that now allow pass-through of EPNG charges to T-1 customers, if caused by T-1 customers.
 - o Addition of Firefly meters to SW Gas T-1 customers.
 - o Implementation of EVA recommendations to tighten controls around T-1 customers to monitor existence of their proper and independent supply contracts (per EVA recommendation in Chapter 2).
- c) Changes to El Paso's tariff that subsequently calculated the required monthly cash-out compared to the month's total scheduled volumes on all transportation contracts, versus formerly calculating the cash-out compared to volumes scheduled only on the "NAESB Swing" designated transportation contracts. FERC approved of this all-party settlement in January 2007 but did not approve the change until March 2007. SW Gas' January 2007 imbalance would have only totaled to about 3% instead of 13% if FERC approval was implemented for January 2007.¹³

¹³ Various email discussions between EVA and SWG dated March 3rd through March 6.

In addition to the above as opportunities arise, EVA recommends that SW Gas continue to press EPNG to improve its quality of 'real time' load estimates that it broadcasts to shippers via EPNG's Electronic Bulletin Board.

Audit Of Selected Transactions

EVA analyzed whether SW Gas followed its policies and procedures based on an audit of selected transactions.¹⁴ EVA believes that overall SW Gas did a good job of following its policies and procedures. EVA's management recommendations for improvement are:

1. Ensure all confirmations with gas suppliers, also known as Exhibit A, include deal transaction dates. Many inadvertently noted the transaction date at the top of the confirmation as the first physical flow date instead of the actual deal date.
2. Ensure all confirmations with suppliers, also known as Exhibit A, include dates of the internal approval next to authorized signature. The VP of Gas Procurement's signature was sometimes present without the date of authorization.
3. Considerably shorten the time lapsed between deal execution and deal confirmation with gas supplier. Some of the audited transactions show lapses of up to three and four months between execution and confirmation, with one and two months for many others. This lapse should probably be no more than one-two weeks at the very most; two to three days would be best. (This will become particularly important for financial derivative transactions where markets can move very quickly.)
4. Include a list of attendees present during the solicitation and purchase of APSP fixed price gas (and during the selection of the index, or term gas, packages) to ensure independence, proper monitoring, and to improve the audit trail. The solicitation information received by EVA for the APSP packages did not include this documentation.
5. Update any old master supply agreements that cap the buyers' liquidated damages at 50 cents per mmBtu to agreements that are based on true-up to actual market during non-performance. Several agreements examined retained the 50 cent cap.

The audit was designed in four parts as described below and focused on the 2006/2007 winter months:

- a) For the Arizona Price Stability Purchases, five solicitation packages were reviewed including all competing bids, notations, forward price curves, signed master contracts, signed confirmations, settlement statements, and the tally of supply acquired to date for the APSP. (Onsite Data Request 9)

¹⁴ This particular audit is addressed by EVA Onsite Data Requests 6, 7, 8, and 9.

- b) For the index, or term, supply element, Planning Department logs were examined that included all of the supplier offers (aka "bids" in SW Gas parlance) received for the 2006/2007 winter months (November-March). Also EVA examined several early and the final runs of the Evaluation Reports that optimized the total universe of supplier offers. (Onsite Data Request 8)
- c) For the index, or term, supply element, six supplier packages were reviewed that represented successful bids consummated by SW Gas including signed master agreements, signed confirmations, and settlement statements. These contracts were also tied back to the Planning Department's selection of optimized contracts. (Onsite Data Request 7)
- d) EVA reviewed the *Arizona Dispatch Guidelines* used by the gas buyers for the months of December 2006 and January 2007. The APSP baseload and index contracts reviewed and discussed above were also noted for inclusion in these guidelines. (Onsite Data Request 6)

The actual supplier contracts reviewed above were selected based on a variety of suppliers, a variety of contract durations, a variety of pricing indices, and a variety of dates that agreements were entered into within the general structure designed by EVA above.

Appendix

Exhibit A-1. El Paso Natural Gas Penalty Matrix

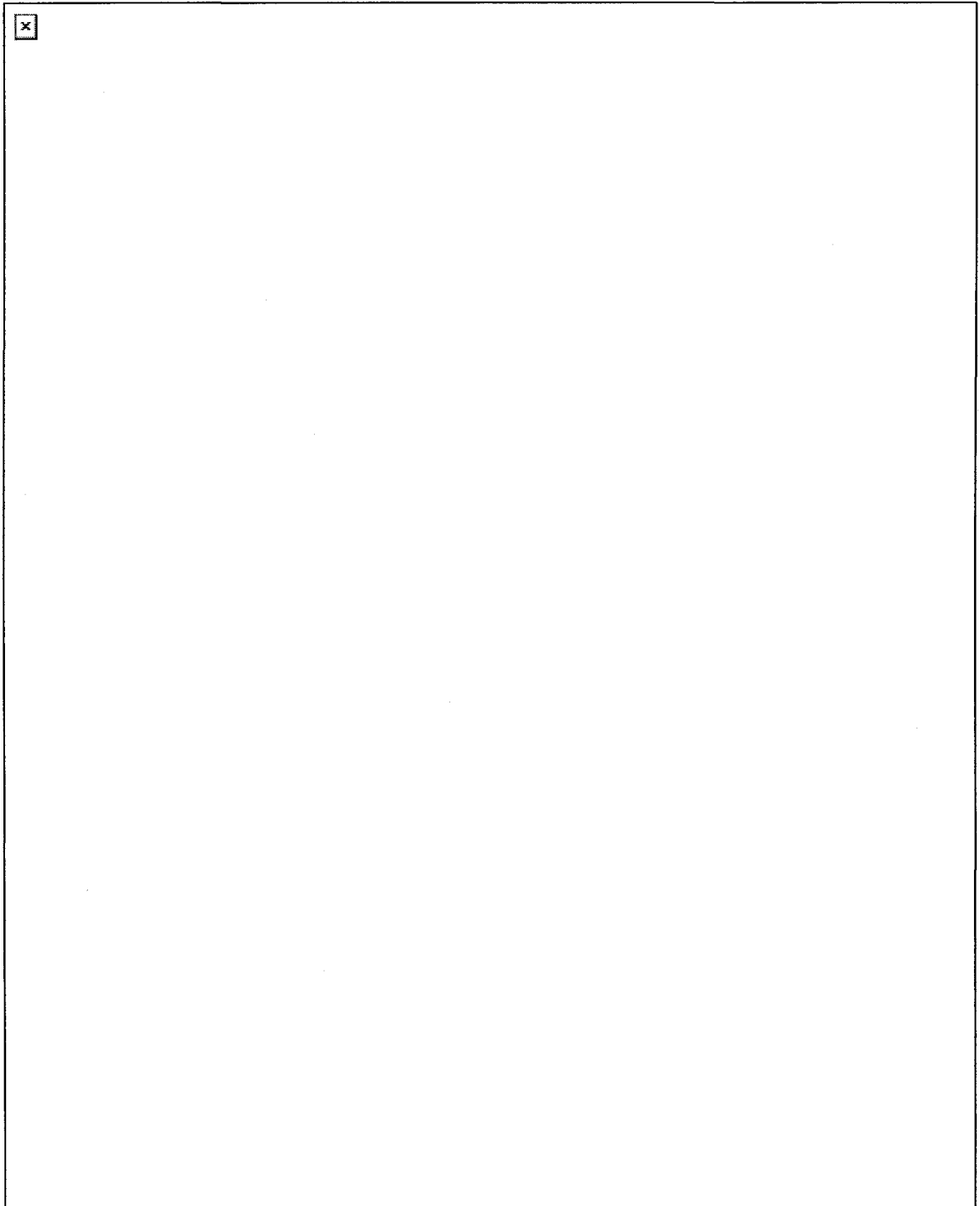


Exhibit A-1. El Paso Natural Gas Penalty Matrix

7	COC (Critical Operating Condition) Imbalance Charge	COC is issued when Operating Conditions continue to threaten the integrity of the pipeline. EPNG may issue COC.	Threshold is 3% of scheduled quantity* at the delivery point under the TSA or 2,000 dth, whichever is greater.	Not applicable	During COC, Daily Imbalance Charges for the first day of the COC will be assessed to any Shipper in the COC area with a daily imbalance that exceeds the threshold of 3% of scheduled quantities. No catch-up nomination allowed during COC.	During a COC, charges equal to the higher of \$10 per dth or two times the highest daily mid-point spot price reported. Shippers should monitor scheduled vs. operational flows under Flowing Gas, SOCOCC.	On a day, a Shipper will be charged the higher of: 1) Hourly Scheduling Penalty; 2) Daily Unauthorized Overrun; 3) MDO/MHO Violation (if Operator and Shipper are the same party); or 4) SOCOCC imbalance penalties.
8	Emergency COC Imbalance Charge	Emergency COC is issued when Operating Conditions continue to threaten the integrity of the pipeline. SOC does not have to be called first.	Threshold is 3% of scheduled quantity* at the delivery point under the TSA or 2,000 dth, whichever is greater.	Not applicable	During COC, Daily Imbalance Charges for the first day of the COC will be assessed to any Shipper in the COC area with a daily imbalance that exceeds the threshold of 3% of scheduled quantities. For any subsequent day(s) of an Emergency COC, no three hold	During a COC, charges equal to the higher of \$10 per dth or two times the highest daily mid-point spot price reported. Shippers should monitor scheduled vs. operational flows under Flowing Gas, SOCOCC.	On a day, a Shipper will be charged the higher of: 1) Hourly Scheduling Penalty; 2) Daily Unauthorized Overrun; 3) MDO/MHO Violation (if Operator and Shipper are the same party); or 4) SOCOCC imbalance penalties.
* For Swing locations, includes all scheduled quantities at the locations where the contract is swing (effective with Settlement)							

Exhibit A-2. New Arizona Combined Cycle And Combustion Turbine Plants 1998-2007

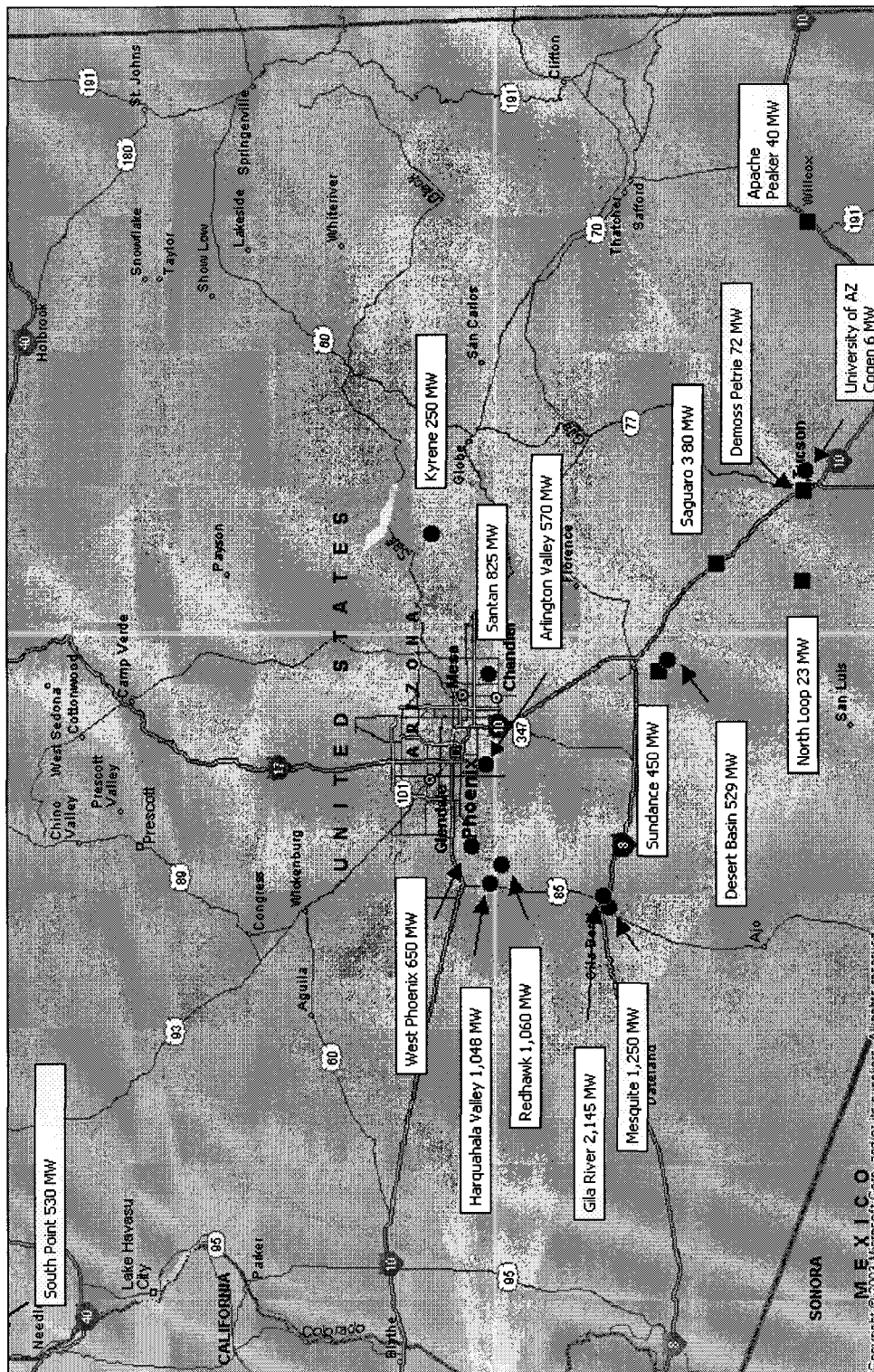


Exhibit A-3. Chronology For 2005 El Paso Natural Gas Rate Case

Docket No. RP04-251 Regarding Segmenting, Pathing, OFOs, and Strained and Critical Condition Provisions

Dec 20, 2004 – The FERC issued Order of settlement in Docket No.04-251 which among other things established Strained and Critical Operating conditions daily pack and draft penalties to become effective 1/1/06.

Docket No. RP05-422 General Rate Case Including New Services and Penalties for Improper Use of the System

June 30, 2005 – El Paso filed a rate case proposing new rates, new services and new penalties presuming that effectiveness would be suspended until 1/1/06. The proposal included MDO/MHO violation penalties, hourly scheduling penalties, hourly interruptible swing charges, non critical daily scheduling pack and draft penalties, and daily over-run charges. That filing proposed a modification to the 11.2 rate protections from the 1995 rate case.

July 29, 2005 – The Commission issued an order accepting and suspending El Paso's primary tariff sheets, subject to conditions and the outcome of a hearing (on rate issues) and a technical conference (for non rate issues i.e., penalties and new services).

October 3, 2005 – EPNG submitted a filing which among other things detailed the distribution of firm capacity (MDQ) to each meter within a D-Code for EOC shippers that were receiving parties.

October 4, 2005 – EPNG filed Offer of Partial Settlement with FERC that deferred EPNG implementing proposed new services including Rate Schedule OPAS (MDOs/MHOs) as well as new penalties and new default service charges until April 1, 2006.

December 2005 – EPNG conducted an open season for an MDQ Adjustment Request process by which shippers were able to request a shifting of MDQs between meters and D-Codes.

December 12, 2005 - FERC approved the Partial Settlement (October 4, 2005 filing) and directed EPNG to file the deferred tariff sheets and provisions 30 days prior to April 1, 2006.

January 1, 2006 The filed rates went into effect subject to refund.

February 16, 2006 – EPNG filed with FERC the results of the December 2005 MDQ Adjustment process.

Exhibit A-3. Chronology For 2005 El Paso Natural Gas Rate Case

March 20, 2006 – FERC issued an Order in response to briefs filed by many parties which addressed Article 11.2 rate issues. In short it preserved the 11.2 rates and provisions under certain conditions but provided that if a customer converts 11.2 a protected FT-1 service to a premium service then the 11.2 a protection would not apply.

March 23, 2006 – FERC issued an Order, regarding issues that were addressed in the Technical Conference process (non rate issues), that accepted El Paso's proposed hourly scheduling penalties but rejected El Paso's proposed non-critical daily pack and draft penalties. El Paso interpreted FERC's Order as approving a daily scheduling "pack penalty".

March 29, 2006 – EPNG requested proposed turn back capacity from interested shippers. Also on March 29, 2006, EPNG filed an "Offer of Settlement" conditionally waiving the implementation of certain provisions of the New Services and charges (penalties) from the effective date of the applicable tariff provisions on April 1, 2006 until June 1, 2006, to provide more time for parties to prepare for the implementation of New Services.

April 18, 2006 – Southwest submitted its request for New Services from El Paso submitted in response to El Paso's Contract Reformation Guidelines. Southwest's premium service contracts went into effect November 1, 2006.

May 16 – May 31, 2006 – EPNG conducted an MDO Open Season for shippers to solicit increased MDOs.

May 31, 2006 – The FERC issued an order rejecting El Paso's compliance filing.

July 24, 2006 – EPNG filed a "MDO Report" with FERC (and on July 31, 2008 filed an update) that detailed the results of the MDO open season, detailing the MDOs to become effective August 1, 2006.

August 1, 2006 – OPASA was executed with MDO quantities filed with FERC in the "Update MDO Report". Since this OPASA, Southwest has submitted to El Paso numerous MDO adjustment requests for incremental MDO at numerous metering points.

December 06, 2006 – EPNG filed offer of settlement supported by all but one party. Articles 6., 7., and 9. deal with penalties, default service charges and credits.

August 31, 2007- FERC approved the Settlement.

Docket No. RP06-368

May 24, 2006 – El Paso filed a waiver request of MDO/MHO violation penalties in non-COCs from 6/1/06 to 7/31/06.

Exhibit A-3. Chronology For 2005 El Paso Natural Gas Rate Case

Docket No. RP06-392

June 13, 2006 El Paso filed a waiver request of hourly scheduling penalty (Critical and non-Critical), hourly authorized and unauthorized overruns, daily variance charges; Rates for FTH and NNTH were discounted to max FT-1 rate; IHSW charges were waived 6/1/06 through 7/12/06 (initially). Extended through 6/6/06.

July 10, 2006 El Paso filed supplement to the waiver, Rates for NNTD were discounted to max FT-1 rate 6/1/06 – 7/12/06.

Docket No RP06-431

July 11, 2006 - El Paso filed a request to waive hourly scheduling penalties (Critical and non-Critical) and hourly authorized and unauthorized overruns daily variance charges and IHSW service charges during 7/13/06 – 7/31/06; For 8/1/06 – 8/31/06, to waive hourly scheduling penalties (Critical and non-Critical) and hourly authorized and unauthorized overruns at delivery locations where Shippers used IHSW service; Continue to waive MHO violation penalties through 8/31/096; HEEN not included in daily-unauthorized overrun calculation; Extension of scheduling accounts through 8/31/06; No cash-out down to 5% for June imbalances.

August 31, 2006 - El Paso filed a request to waive daily variance charge, MDO violation penalty, MHO violation penalty, hourly scheduling penalty (Critical and non- Critical); August requirement that a shipper have IHSW to receive waiver of hourly scheduling penalties no longer applies; Continue use of scheduling accounts.

September 29, 2006 - El Paso filed waiver of tariff provision in order to continue use of scheduling accounts through 1/31/07.

Docket No. RP07-108

December 13, 2007 - El Paso filed a request to waive daily variance charges for shippers who packed the system, thereby helping to mitigate the Critical Condition (daily Variance charges deemed to be zero for the "higher-of-test"); Contract and service related penalties (i.e. daily and hourly Unauthorized overruns, hourly scheduling penalties, MHO/MDO Violation penalties) billed at the non-Critical rate for all shippers.

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON

Chairman

WILLIAM A. MUNDELL

Commissioner

JEFF HATCH-MILLER

Commissioner

KRISTIN K. MAYES

Commissioner

GARY PIERCE

Commissioner

IN THE MATTER OF THE APPLICATION OF)
SOUTHWEST GAS CORPORATION FOR THE)
ESTABLISHMENT OF JUST AND)
REASONABLE RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF SOUTHWEST GAS)
CORPORATION DEVOTED TO ITS)
OPERATIONS THROUGHOUT ARIZONA.)

DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

STEPHEN L. THUMB

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

My testimony in this proceeding addresses a number of issues related to Southwest Gas Corporation's ("Southwest Gas" or "Company") gas procurement during the period of September 2004 through April 2007. Specifically, my testimony focuses on Southwest Gas' interstate pipeline capacity portfolio and the Company's management of its pipeline capacity, as well as the pipeline penalties incurred during this period. Ms. Rita Beale and myself, both of Energy Ventures Analysis Inc. ("EVA"), conducted a review Southwest Gas' gas procurement, policies, procedures, and practices during the first quarter of 2008. This review included document reviews, onsite interviews, and numerous follow-up teleconference calls and emails between EVA and Southwest Gas. A detailed discussion of the El Paso Natural Gas Pipeline dynamics is contained in Exhibit SLT-2, as well as Chapter 2 of a lengthy report authored by Energy Ventures Analysis.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Stephen L. Thumb. I am a Principal employed with Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, VA 22209-1706.

Q. Please summarize your educational background and professional experience.

A. I am a graduate of Northwestern and American Universities from which I have received a B.S. in Chemical Engineering and an MBA in Finance, respectively. For almost 20 years I have consulted to the natural gas industry and currently co-direct the oil and gas practice for EVA, which is nationally known for its work in the energy and emission fields. Prior to my tenure at EVA, I spent 15 years in the oil and gas industry, including Vice President of Planning for one of the largest independent exploration and production companies. I have authored or co-authored over 40 reports for the Electric Power Research Institute ("EPRI") and the Gas Institute of Technology on key topics concerning the gas industry. Exhibit SLT-1 presents my resume.

Q. What is the purpose of your Testimony?

A. Together with Ms. Rita Beale, who also is a principal at EVA, I am appearing on behalf of the Arizona Corporation Commission ("ACC") Utilities Division ("Staff") to address the prudence of Southwest Gas Corporation's ("Southwest Gas" or "Company") gas procurement practices over the time frame spanning September 2004 through April 2007. Specifically, my testimony focuses on Southwest Gas' interstate pipeline capacity portfolio and the Company's management of its pipeline capacity, as well as the pipeline penalties incurred during this period.

1 **Q. Has a complete assessment of your findings been presented in the report attached to**
2 **this Testimony in Exhibit SLT-2?**

3 A. Yes. Chapter 2 of Exhibit SLT-2 presents my entire analysis of Southwest Gas' interstate
4 pipeline capacity portfolio and related issues.

5
6 **SUMMARY OF TESTIMONY AND RECOMMENDATIONS**

7 **Q. What are your findings?**

8 A. In my review of Southwest Gas' interstate pipeline capacity portfolio, I concluded:

9
10 1. The El Paso Natural Gas ("EPNG") pipeline tariff (i.e., EPNG tariff effective
11 January 1, 2006, subject to revision) enacted during this time frame represented a
12 total and complete restructuring of interstate pipeline services for Southwest Gas.

13
14 2. As a result of this new EPNG tariff, the annual fixed charges paid by Southwest
15 Gas for interstate pipeline capacity increased appreciably.

16
17 3. Southwest Gas, under this new EPNG tariff, did incur additional charges and
18 penalties, but the incursion of these additional charges and penalties appears to
19 have been reasonable.

20
21 4. Southwest Gas is attempting to diversify its interstate pipeline capacity portfolio
22 and Southwest Gas should continue seeking access to storage capacity, particularly
23 market-area storage capacity. Concerning the latter, it is suggested that the
24 Commission may want to consider taking an active role in promoting the
25 development of market-area storage in Arizona.
26

1 5. Additionally, Southwest Gas should increase the documentation and requirements
2 for its transportation-only customers. Also, Southwest Gas should make its Daily
3 Forecasting Accuracy Improvement Task Force a permanent entity.

4
5 **EPNG RATE CASE**

6 **Q. Did the EPNG Rate Case represent a significant event?**

7 A. Probably the most significant event during the audit period was the total and complete
8 restructuring of the EPNG pipeline tariff and the impact it had on Southwest Gas, as well
9 as other East of California customers. This single event appears to have had an impact on
10 nearly every phase of Southwest Gas' operations during the audit period. It is difficult to
11 note succinctly the enormity of this change and its impact on Southwest Gas.

12
13 **Q. Can you summarize the major changes in the EPNG Rate Case in relatively**
14 **simplified terms?**

15 A. Yes. Prior to the EPNG rate case, East of California customers, including Southwest Gas,
16 were under a 'full requirements' system for their gas loads. A key feature of this system
17 was that it allowed East of California customers to vary their gas loads from minimum to
18 peak loads at no additional charge. In colloquial terms within the industry, this is referred
19 to as 'free swing' capability.

20
21 The EPNG rate case, for a variety of reasons, completely eliminated this 'full
22 requirements' system and replaced it with a system that, in essence, allowed for zero
23 swing capability in either daily or hourly loads. In addition, the EPNG rate case created a
24 series of new pipeline tariffs and services, each with unique terms and conditions. These
25 pipeline services were more expensive than those offered in the past.

26

1 In very simplified terms, the EPNG system for East of California was converted from (a) a
2 full requirements concept that provided swing services to (b) a system that, in essence,
3 provided no swing services.¹

4
5 **Q. Can an East of California interstate pipeline customer operate without swing**
6 **services?**

7 A. No. This is true for Southwest Gas, as well as other East of California customers, since
8 they serve customers that do not consume gas on a levelized basis (i.e., 1/24th of the daily
9 requirements each and every hour). A classic example is a residential customer, which
10 during the night time hours (i.e., when sleeping) uses less gas than during the day time
11 hours. Similar conditions exist for Southwest Gas' commercial and industrial customers.

12
13 **Q. Does the lack of market-area storage in Arizona make it more difficult for SW Gas to**
14 **meet its customer load requirement without any swing reasons?**

15 A. Yes. Market-area storage would allow Southwest Gas, to a degree, to be better able to
16 meet the swing load requirements of its customers', however, none currently exists in
17 Arizona.

18
19 **Q. Were there other factors that made it difficult to comply with the new EPNG**
20 **operational requirement of having no variations in load requirements?**

21 A. Yes. The new EPNG operational concept of no swing services was extended to the
22 smallest divisible unit on the EPNG system, namely every meter and/or delivery code
23 ("D-code"). In addition, if there were multiple contracts behind a meter, the concept was
24 extended to each contract. Basically, the new EPNG operational concept did not allow for
25 any variations in daily or hourly gas loads anywhere on its system.

¹ While this summary adequately represents this major transition for the East of California customers, technically the 'full requirements' era ended in September 2003.

1 **Q. What happens if there are variations in Southwest Gas's actual gas load**
2 **requirements?**

3 A. Under the initial proposal for the EPNG tariff, if there were any variations in Southwest
4 Gas loads from those scheduled on a daily or hourly basis, then Southwest Gas would
5 incur additional charges and penalties. Subsequently in the August 31, 2007 FERC Order,
6 Southwest Gas and the other East of California customers were able to establish a
7 tolerance band for these variations, as discussed in the report contained in Exhibit SLT-2.

8
9 **Q. Did Southwest Gas have any other alternatives?**

10 A. Yes. Southwest Gas could have contracted for some of the premium services offered by
11 EPNG. These premium services provided for some variation in load requirements, but
12 they were more expensive. However, even if Southwest Gas were to have subscribed to
13 some of these more expensive premium services, it still could have been exposed to
14 additional charges and penalties.

15
16 **Q. Did Southwest Gas initially subscribe to these premium services?**

17 A. No.

18
19 **Q. Why not?**

20 A. The EPNG rate case was arguably one of the most arduous, complex, lengthy and
21 contested interstate pipeline rate cases. At the time Southwest Gas had to make its
22 selection of the new EPNG transportation services, it (1) had no operational experience
23 with this new and very complex system, (2) did not have a full perspective on the costs of
24 the various new pipeline services, and (3) lacked almost any appreciation of either the
25 potential for penalties or their magnitude. As a result Southwest Gas, in order to minimize

1 costs for its transportation services, initially focused primarily on using the less costly
2 FTH-1 service, in order to meet its interstate transportation requirements.

3
4 Even with the selection of the less costly FTH-1 service there would be a substantial
5 increase in Southwest Gas' fixed annual transportation expense. At the time there was
6 still uncertainty over the exact EPNG rates for each transportation service and some
7 concern that total fixed annual transportation expenses could double. Subsequently, after
8 extensive efforts by Southwest Gas and the other East of California customers, the EPNG
9 rates for the various transportation services were reduced from EPNG's initial proposal,
10 such that Southwest Gas's fixed annual transportation costs did not double, but it did
11 increase about 60 percent.

12
13 **Q. Were the other East of California customers in a similar situation?**

14 A. Yes. There was considerable uncertainty among the other East of California customers
15 which caused many of them to follow a similar strategy in selecting new EPNG
16 transportation services. For example, none of the Arizona customers initially selected any
17 of the relatively expensive no-notice pipeline services, even though the use of no-notice
18 service very likely would have minimized a customer's exposure to additional charges and
19 penalties.

20
21 **Q. Was Southwest Gas's selection of new EPNG transportation services at that time**
22 **reasonable?**

23 A. Yes. At the time, the optimum economic trade-off between the cost of pipeline services
24 and minimization of additional charges and penalties was probably not knowable.
25

ADDITIONAL CHARGES AND PENALTIES

Q. Did Southwest Gas incur any additional charges and penalties?

A. Yes. Prior to considering the impact of any refunds, Southwest Gas incurred approximately \$6.7 MM in additional charges and penalties during 2006 and 2007. These additional charges and penalties tend to fall into two categories, namely; (a) those charges and penalties associated with a relatively unique force majeure situation that existed during the November 30, 2006 to December 4, 2006 time frame (i.e., approximately \$3.4 MM) and (b) other charges and penalties incurred during this time frame (i.e., approximately \$3.3 MM).

Q. Describe the additional charges and penalties in the second category.

A. A detailed breakdown of these additional charges and penalties is provided in Exhibit 2-1 of the report attached to this Testimony (Exhibit SLT-2). Of the eight types of additional charges and penalties presented in this exhibit, three accounted for 75 percent of the total. These three major additional charges and penalties are (a) the daily variance penalty (\$1.2 MM), (b) the maximum daily overrun ("MDO") violation penalty (\$0.7 MM) and (c) the maximum hourly violation ("MHO") penalty (\$0.6 MM).

Q. How much of this second category of additional charges and penalties were refunded?

A. Approximately \$1.7 MM of the \$3.3 MM of the subject additional charges and penalties were subsequently refunded. In particular, after considerable effort by Southwest Gas and the other East of California customers, all of the daily variance penalties eventually were refunded (i.e., about \$1.2 MM).

1 **Q. Did Southwest Gas take any actions to minimize these additional charges and**
2 **penalties?**

3 A. Yes. Southwest Gas took a very proactive role in attempting to minimize these additional
4 charges and penalties. These proactive efforts by Southwest Gas included:

- 5
- 6 • Intense efforts to have EPNG correctly assign or modify MDO and MHO levels
- 7 for various taps;
- 8
- 9 • Efforts to revise various segments of the EPNG tariff; and
- 10
- 11 • Judiciously increasing the level of premium services over time.
- 12

13 **Q. The MDO and MHO penalties were among the largest penalties during this time**
14 **frame. Is that correct?**

15 A. Yes. The MDO and MHO penalties accounted for about 39 percent of the total additional
16 charges and penalties before refunds and about 65 percent after refunds.

17

18 **Q. Describe the MDO and MHO penalties.**

19 A. Under EPNG's new tariff the concept of no swing capability concept was transferred
20 down to the lowest possible level on the pipeline system, namely the individual meter. As
21 a result, any variance in either daily gas loads from designated levels at an individual
22 meter MDO or even hourly loads MHO at an individual meter resulted in a penalty under
23 EPNG's system. In addition, the MDO and MHO levels were assigned by EPNG based
24 upon an internal EPNG assessment that was derived from a historical usage algorithm.
25 Subsequently, it was proven that EPNG's assessment for several meters was in error.
26 Furthermore, this concept was extended downstream to each supply contract behind a

1 given meter, which made the implementation of the EPNG tariff even more complex and
2 operationally almost a nightmare. Lastly, the concept also was applied upstream to the
3 EPNG D-codes.²
4

5 **Q. Was Southwest Gas affected more by the MDO and MHO provisions in the new**
6 **EPNG tariff than the other East of California customers?**

7 A. Yes. Because of certain characteristics of the EPNG system, Southwest Gas, more than
8 any other East of California customer, is affected more by the MDO and MHO provisions
9 in the EPNG tariff. This occurs because Southwest Gas takes gas from more points (i.e.,
10 taps) on the EPNG system than all the remaining East of California customers combined.³
11 This unusual situation is, in large part, an artifact of the full requirements era for the
12 EPNG pipeline.
13

14 **Q. What actions did Southwest Gas take to minimize these MDO and MHO penalties?**

15 A. Southwest Gas undertook a number of actions to minimize the MDO and MHO penalties.
16 It is difficult to succinctly summarize these actions because of both (1) the large number
17 of actions and (2) the enormous variety of actions taken, as the circumstances for the
18 nearly 335 Southwest Gas taps tend to be site specific. However, in general, the overall
19 process requires SW Gas to identify flaws with EPNG's MDO/MHO provisions and make
20 a filing with EPNG for a correction and/or a waiver of penalties. Each action can be a
21 rather lengthy process as (1) the burden of proof is on Southwest Gas, (2) hydraulic
22 modeling of the EPNG system is required in some cases, (3) the request and supporting
23 information usually has to be reviewed verbally with the EPNG staff, (4) a formal request
24 must be filed with EPNG and (5) a formal response must be received from EPNG.

² In simplified terms a D-code is a group of meters that are usually within close geographic proximity.

³ SW Gas has approximately 215 taps on the EPNG system that have active EPNG telemetry and approximately 120 taps that Southwest reads on monthly basis (i.e., charts) with this data manually provided to EPNG.

1 To date Southwest Gas has been successful in obtaining MDO/MHO increases at
2 approximately 145 metering points, which has been a significant factor in minimizing
3 future charges and penalties. Exhibit 2-3 in the attached report (Exhibit SLT-2) provides
4 highlights for several of these actions.

5
6 **Q. What other actions did Southwest Gas take to minimize the various types of**
7 **additional charges and penalties?**

8 A. In addition to seeking revisions to the MDO and MHO provisions in the EPNG tariff,
9 Southwest Gas has (a) undertaken a number of efforts, along with other East of California
10 customers, to revise various segments of the EPNG tariff in order to minimize additional
11 charges and penalties and (b) over the course of time judiciously increased its level of
12 premium transportation services. Specifics concerning these additional actions are
13 presented in the attached report (Exhibit SLT-2; see pages 2-15 through 2-18).

14
15 **Q. Concerning this second category of additional charges and penalties, was Southwest**
16 **Gas imprudent in incurring any of these additional charges and penalties?**

17 A. No. Under the new EPNG tariff it is nearly impossible to operate without incurring some
18 additional charges and penalties. The key alternative is to subscribe to a significant level
19 of EPNG's premium transportation services; however, this would increase the fixed
20 annual transportation costs and would not eliminate necessarily Southwest Gas's exposure
21 to additional charges and penalties – although it would help minimize the exposure.

22
23 The optimal economic tradeoff between fixed annual transportation costs and potential
24 exposure to additional charges and penalties requires certainty concerning unit rates for
25 the various transportation services and experience concerning the potential exposure to
26 these additional charges and penalties at a very granular level. During the majority of the

1 audit period, Southwest Gas had neither of these latter two items and, as a result, could not
2 make the optimal selection. Faced with this dilemma Southwest Gas chose to minimize
3 the overall increase in its fixed annual transportation costs, which is not an imprudent
4 action.

5
6 In addition, Southwest Gas took a significant number of steps to revise the EPNG tariff
7 provisions in order to both obtain refunds and to minimize the future exposure to the
8 additional charges and penalties. Nevertheless, going forward, it is likely Southwest Gas
9 still will incur some additional charges and penalties under the new, but revised EPNG
10 tariff.

11
12 **EVENTS OF NOVEMBER 30 THROUGH DECEMBER 4, 2006**

13 **Q. There also were additional charges and penalties associated with the events of**
14 **November 30, 2006 through December 4, 2006. Is that correct?**

15 A. Yes. A rapidly moving cold front caused well freeze-offs in the San Juan basin,⁴ which in
16 turn caused suppliers to declare a force majeure event and curtail supplies. Under the new
17 EPNG tariff, even though this was a force majeure event for the affected suppliers,
18 Southwest Gas was assessed \$3.4 MM in penalties by EPNG.

19
20 **Q. What were weather conditions during this time frame?**

21 A. While temperatures had been relatively mild for most of November, a cold front quickly
22 moved through the Southwest at the end of November. This cold front caused
23 temperatures in the San Juan basin to decline about 42°F in approximately 40 hours, with
24 about 60 percent of the temperature decline occurring in the last 18 hours. At the low
25 point temperatures in the San Juan basin reached 5°F.

⁴ While the primary focus of this section of testimony is on San Juan basin supplies, there also were well freeze-offs in the Permian basin, as discussed in the report contained in Exhibit SLT-2.

1 In addition, this rapidly moving cold wave also impacted the major load centers for
2 Southwest Gas, which in turn caused gas demand to spike. Temperatures in Phoenix
3 declined about 18°F in approximately 15 hours to just above freezing, while in Tucson the
4 temperature declined about 28°F in approximately 15 hours to below freezing (i.e., about
5 27°F).

6
7 **Q. What happened to the EPNG system?**

8 A. This loss of supply from the San Juan basin caused linepack on the EPNG system to drop
9 dramatically and exceed the low threshold point for strained operating conditions
10 ("SOC"). This placed the EPNG system in a critical operating condition ("COC"), which
11 is a very serious event for any pipeline. Exhibit 2-8 in the attached report (Exhibit SLT-2)
12 provides a graphical illustration of the changes in the EPNG linepack.

13
14 **Q. What was the impact of these events on Southwest Gas?**

15 A. The net result on Southwest Gas of this rapidly moving cold front was that (a) gas demand
16 spiked well beyond forecasted volumes and (b) producers in the San Juan basin invoked
17 force majeure provisions after Southwest Gas had scheduled its gas supplies.
18 Subsequently, Southwest Gas was assessed penalties by EPNG.

19
20 **Q. Could the penalties assessed by EPNG have been higher?**

21 A. Yes. Under the rigid requirements of the new EPNG tariff, these events resulted in
22 Southwest Gas being assessed \$3.4 MM in penalties, although the figure could have been
23 higher (i.e., about \$7 MM) if it had not been for earlier proactive initiatives by Southwest
24 Gas and the other East of California customers.

25

1 **Q. If a similar event occurred today, would Southwest Gas be assessed penalties by**
2 **EPNG?**

3 A. Yes. However, initiatives by Southwest Gas and the other East of California customers
4 that were enacted subsequent to the November 30 through December 4, 2006 time frame
5 would have the net effect of reducing these penalties about 85 percent if the same set of
6 conditions were to occur today.

7
8 **Q. Did Southwest Gas accurately forecast its load requirements during this time frame?**

9 A. No. Actual consumption by Southwest Gas's customers on November 30 was
10 approximately 28 percent, or 108,000 Dth, greater than the initial forecast for the day.

11
12 **Q. What impact did this under-forecasting of load requirements have on the penalties**
13 **assessed by EPNG?**

14 A. Limited, if any. The primary factor behind the penalties assessed by Southwest Gas
15 during this time frame was the curtailment of natural gas production in the San Juan basin.
16 It is likely that gas supplies available to Southwest Gas would have been limited no matter
17 how much gas it had scheduled. In addition, it is difficult to chastise Southwest Gas's
18 management for this disparity, in light of the rapidly changing weather conditions.

19
20 **Q. Did Southwest Gas take any steps to improve its forecasting system?**

21 A. Yes. No LDC likes to see actual consumption exceed forecasted levels by 28 percent,
22 even under adverse weather conditions. This includes Southwest Gas, which subsequently
23 set up a multi-department task force to both audit the events of this period and investigate
24 ways of improving its forecasting system.

25

1 **Q. What were the results of this task force?**

2 A. This task force, which was referred to as the Daily Forecasting Accuracy Improvement
3 Task Force and was established in December 2006, met on a monthly basis through the
4 end of 2007 and reviewed a number of topics and alternatives for improving Southwest
5 Gas's daily gas forecasting system. As a result of this task force, Southwest Gas took the
6 following actions:

- 7
- 8 • **Weather Services:** Southwest Gas subscribed to an additional or second weather
9 service, which provides two updates to the initial weather forecast for a given day.
10 Projections for the two weather forecasts are compared and contrasted.
 - 11
 - 12 • **Gas Day Model:** Southwest Gas contracted with Marquette University to
13 investigate and make improvements in its gas model, which included the
14 incorporation of non-linear relationships between consumption and heating degree
15 days at extreme temperatures.
 - 16
 - 17 • **Other Items:** Southwest Gas implemented the usage of several other analytical
18 techniques to augment its Gas Day Model, including the use of scatterplots and the
19 development of 24-hour load curves for incremental heating degree days.
- 20

21 **Q. What was the impact of the curtailed gas supplies?**

22 A. The total lost San Juan production to the EPNG system was about 0.5 BCFD during this
23 event. For Southwest Gas, the difference between Cycle 4 scheduling and delivered San
24 Juan supplies was approximately 83,000 Dth (i.e., about 0.08 BCFD). The latter is likely
25 the best indication of lost supply for Southwest Gas.

26

1 **Q. Was the curtailed gas supply the primary reason for the penalties assessed by EPNG**
2 **during this time frame?**

3 A. Yes. By far the most significant factor behind the penalties assessed for Southwest Gas
4 during this time frame was the curtailment of natural gas production in the San Juan basin.
5 The latter occurred because of both the severity of the weather and its rapid change, which
6 appears to have caught most, if not all, of the southwestern gas industry off guard.

7
8 **Q. If Southwest Gas had forecasted and scheduled a higher level of gas demand, would**
9 **Southwest Gas have been able to obtain more gas supplies?**

10 A. Even if Southwest Gas scheduled a higher level of gas supply, it is doubtful that overall
11 supplies would have increased appreciably, as the well freeze-off conditions were
12 epidemic throughout the basin. Instead, the amount of curtailed production for Southwest
13 Gas likely would have increased under a scenario of an even higher level of scheduled
14 supplies by Southwest Gas.

15
16 **Q. If Southwest Gas had had access to market-area storage, could the overall supply**
17 **have been increased and some or all of the penalties been avoided?**

18 A. Yes. Access to market-area storage would have allowed Southwest Gas to better adapt to
19 this unusual set of events; however, no market-area storage exists in Arizona.

20
21 **Q. Concerning the additional charges and penalties during the November 30 to**
22 **December 4, 2006 time frame, was Southwest Gas imprudent in incurring any of**
23 **these additional charges and penalties?**

24 A. No. Both the severity of the weather and its rapid change appears to have caught most of
25 the southwestern gas industry off guard, with well freeze-offs forcing producers to declare
26 force majeure conditions, particularly in the San Juan basin. From the perspective of

1 Southwest Gas, the gas supplies available to serve its customers was limited no matter
2 how much gas it had scheduled. Southwest Gas was limited in its ability to respond to
3 these unusual and rapidly changing events because of the lack of timely receipt of
4 information from EPNG and the suppliers. In addition, it appears that even if Southwest
5 Gas had received this information on a more timely basis, it is doubtful Southwest Gas
6 could have obtained a significant increase in gas supplies, as the entire region was under
7 the equivalent of emergency conditions. Despite these mitigating factors, under the newly
8 instituted EPNG tariff Southwest Gas was assessed penalties.

9
10 Subsequent action by Southwest Gas and the other East of California customers would
11 significantly lower the magnitude of these penalties if similar events were to occur today.
12

13 **OTHER RELATED MATTERS**

14 **Q. Are there other related matters that you have examined?**

15 A. Yes. I have examined and have recommendations for the following items that are either
16 directly or indirectly related to Southwest Gas' overall interstate pipeline capacity
17 portfolio:

- 18 • Southwest Gas's transportation-only customers
- 19 • Storage
- 20 • Gas sharing policies within Arizona
- 21 • Supply diversification

22
23 **Q. Are these related items discussed in the report attached to your testimony in Exhibit**
24 **SLT-2?**

25 A. Yes.
26

1 **Q. Please summarize your major recommendations on these related items.**

2 **A. My recommendations for these related items are as follows:**

- 3
- 4 • **Transportation-Only Customers:** While Southwest Gas, as documented in ACC
- 5 Docket No. G-01551A-06-0746 Decision No. 69668, has taken steps to require
- 6 that transportation-only customers comply with the EPNG tariff, in the future
- 7 Southwest Gas should become firmer with its transportation-only customers and
- 8 require detailed documentation of both supply contracts and interstate capacity
- 9 contracts, as well as compliance with EPNG's new tariff provisions. While it is
- 10 understandable that this may not have been a high priority for Southwest Gas in
- 11 the past, in light of all the other items undertaken by Southwest Gas' management
- 12 to adapt to the new EPNG tariff, it should be going forward. Actions by these
- 13 transportation-only customers, if not rigorously monitored, can expose Southwest
- 14 Gas to additional charges and penalties, which would be unfair to Southwest Gas'
- 15 other customers.
- 16
- 17 • **Storage:** There is a genuine need for market-area storage within Arizona in light
- 18 of the fact that suppliers likely will be curtailed in the future and the significant
- 19 growth in gas demand within Arizona. As a result, the ACC should consider
- 20 developing additional policies to promote the development of market-area storage
- 21 in Arizona and in particular consider events to resurrect the Copper Eagle project.
- 22 As discussed in the report contained in Exhibit SLT-2, the potential worst case
- 23 consequences of not having access to market-area storage when a major well
- 24 freeze-off event occurs include the potential for a large number of pilot lights to go
- 25 out and electric brownouts. Suggestions for such policies and actions are
- 26 contained in the attached report (Exhibit SLT-2).

- 1 • **Gas Sharing Policies:** Until the point that market-area storage becomes a reality
2 in Arizona, it is recommended that the ACC develop and implement policies that
3 would promote the sharing of gas supplies among the major users of interstate
4 pipeline capacity in Arizona during extreme conditions. Initial suggestions for
5 such a policy are contained in the attached report (Exhibit SLT-2).
6
- 7 • **Supply Diversification:** While Southwest Gas has taken efforts to diversify its
8 future pipeline capacity portfolio, it is recommended that Southwest Gas carefully
9 track the likelihood of LNG imports entering the Southwest Gas market and
10 consider gaining access to such supplies, in an effort to diversify its gas supplies
11 and reduce its dependence on the San Juan basin.
12

13 **Q. Are there any other recommendations you have?**

14 A. Yes, I have two additional recommendations. The first recommendation is that Southwest
15 Gas should make its Daily Forecasting Accuracy Improvement Task Force a permanent
16 task force within the Southwest Gas organization and document such in its policies and
17 procedures. While the frequency of meetings, based on the judgment of Southwest Gas
18 management, could be reduced, the task force should continuously examine means of
19 improving the firm's forecasting system. Southwest Gas's policies should also require
20 ongoing validation and back-testing of its daily load forecast, along with its required
21 frequency.
22

23 **Q. What is your second additional recommendation?**

24 A. It also is recommended that Southwest Gas develop a plan and timetable for implementing
25 each of the recommendations in this testimony. Furthermore, this plan and associated
26 timetable should be submitted to the ACC by December 1, 2008 as a report to the

1 Commission, documenting compliance with the recommendations above. Staff shall then
2 review Southwest Gas's filing and Staff shall file, as a compliance item in this docket, a
3 report to the Commission on Southwest's compliance with the recommendations above.
4

5 **Q. Does this conclude your Direct Testimony?**

6 **A.** Yes, it does.

RESUME OF STEPHEN L. THUMB

EDUCATION

C.P.A. West Virginia, 1977
M.B.A. Finance, American University, 1972 (cum laude)
B.S. Chemical Engineering, Northwestern University, 1967

EXPERIENCE

Current Position

Stephen Thumb joined Energy Ventures Analysis in 1988 and became a partner in 1990. Mr. Thumb is responsible for the oil and natural gas practice at Energy Ventures Analysis, Inc. (EVA) and has been involved in a wide variety of projects for each fuel, primarily for industrial and power industry clients. Examples include preparation of strategic plans, development of bidding programs for natural gas supplies, coordination of market studies, production of price forecasts, as well as being an expert witness. Mr. Thumb has presented testimony before the U.S. Senate. In addition, Mr. Thumb has authored or co-authored over 25 EPRI and Gas Technology Institute (GTI) reports on key topics concerning oil and natural gas. The types of projects in which Mr. Thumb is involved are described below:

Natural Gas Procurement

Evaluates natural gas procurement strategies for consumers taking into account the changing regulatory environment. For example, the procurement must address the mix of long- and short-term supply contracts, the mix of firm and interruptible transportation, and the mix of services.

Natural Gas/Oil Industry Analyses

Evaluates the natural gas and oil industries for clients concerned about supply options and availability. Studies have focused on structural issues such as pipeline and storage capacity.

Forecasting

Provides clients with general or customized forecasts of natural gas and oil prices. Natural gas price forecasts are developed on both a wellhead or burner tip basis. Oil prices are developed for crude and refined oil products.

Financial Analysis

Serves as EVA's senior financial analyst and performs financial analyses as required.

Acquisition and Divestiture Analysis

Has directed or been involved with acquisition and divestiture analyses for both energy related firms and specific energy assets. The latter includes the potential divestiture or acquisition of over 40 different power plants, most of which were gas-fired, several major interstate pipelines and gathering systems, storage fields and processing plants.

Prior Experience

Before joining Energy Ventures Analysis, Mr. Thumb had 15 years of diversified industry experience having worked for three Fortune 100 companies. From 1982 to 1988, Mr. Thumb worked for Burlington Northern, Inc., most recently as Vice President of Planning for Meridian Oil, a wholly-owned subsidiary. Mr. Thumb's responsibilities included acquisitions, economic analysis, strategic plans, annual budgeting. Mr. Thumb's most significant accomplishment was the identification, analysis, and implementation of two major energy-related acquisitions (the El Paso Co. and Southland Royalty).

From 1974 to 1982, Mr. Thumb worked for Ashland Oil, Inc., most recently as Executive Assistant to the Chief Executive Officer. Mr. Thumb managed a number of special projects in the areas of operations and finance such as the development and marketing of a \$200 million institutional drilling fund and an analysis of the firm's largest international oil production contract. Mr. Thumb also established a special employee incentive program for an oil and gas subsidiary in consultation with human resources and coordinated the redesign of an exploration and production accounting function.

From 1972 to 1974, Mr. Thumb worked for Nuclear Fuel Services, a wholly-owned subsidiary of Getty Oil. Mr. Thumb, as Manager for Financial Planning, was responsible for the preparation of economic analyses and long- and short-term plans. He also assisted the controller in numerous accounting functions.

From 1967 to 1972, Mr. Thumb worked for the Division of Naval Reactors, a joint operation of the Atomic Energy Commission and the U.S. Navy, as an engineer in the fluid design section for surface ships and the radiological and chemical sections. From 1965 to 1967, Mr. Thumb worked at the Naval Ordnance Plant as a chemical and metallurgical technician.

**Gas Procurement Audit -In The Matter Of The
Southwest Gas Rate Case (Docket No. G-
01551A-07-0504)**

MARCH 2008

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EXECUTIVE SUMMARY

Overview

This report was prepared at the request of the Staff of the Arizona Corporation Commission-Utilities Division ("ACC") to address the prudence of Southwest Gas Corporation's ("SW Gas") gas procurement practices over the time frame spanning September 2004 through April 2007. The two chapters of this report serve as Exhibit SLT-2 and Exhibit RRB-2 of the respective testimonies of Stephen L. Thumb and Rita R. Beale of Energy Ventures Analysis, Inc. in the matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rate of Return On The Fair Value Of The Properties Of Southwest Gas Corporation devoted To Its Operations Throughout Arizona, Docket No. G-01551A-07-0504. In this particular context, gas procurement refers to Southwest Gas' portfolio of gas supply and pipeline capacity and the related policies, procedures, and practices. Chapter 2 of this report serves as Exhibit SLT-2 and examines Southwest Gas' pipeline portfolio and related practices. Chapter 3 of this report serves as Exhibit RRB-2 and examines Southwest Gas' supply portfolio and related practices during the audit period.

Findings

The primary findings of the Chapter 2 review of SW Gas' interstate pipeline capacity portfolio can be summarized as:

- The El Paso Natural Gas (EPNG) pipeline tariff (i.e., EPNG tariff effective January 1, 2006, subject to revision) enacted during this time frame represented a total and complete restructuring of interstate pipeline services for SW Gas. This single event appears to have had an impact on nearly every phase of SW

Gas' operations during the audit period. It is difficult to note succinctly the enormity of this change and its impact on SW Gas. In very simplified terms the EPNG system for East of California was converted from a (1) full requirements concept that provided swing services to (b) a system that, in essence, provided no swing services.

- As a result of this new EPNG tariff, the annual fixed charges paid by SW Gas for interstate pipeline capacity did increase appreciably. Subsequently, after extensive efforts by SW Gas and the other East of California customers, the EPNG rates for the various transportation services were reduced from EPNG's initial proposal, such that SW Gas' fixed annual transportation costs did not double, but it did increase about 60 percent.
- SW Gas under this new EPNG tariff did incur additional charges and penalties, but the incursion of these additional charges and penalties appears to be reasonable. Under the new EPNG tariff it is nearly impossible to operate without incurring some additional charges and penalties. At the beginning the optimum economic trade-off between the cost of pipeline services and minimization of additional charges and penalties was probably not knowable. Subsequently SW Gas took a very proactive role in attempting to minimize additional charges and penalties.

The primary findings of Chapter 3 review of gas supply, policies, and procedures can be summarized as:

- Southwest's gas supply strategies were prudent and reasonable.
- Its gas supply strategies were effective at providing firmness of supply, providing price stability, and reducing price volatility, main objectives of SW Gas' Arizona Price Stabilization Plan.
- The gas supply transactions executed by Southwest and prices paid were reasonable and prudent.
- The price indices used by SW Gas in setting their natural gas purchase prices are standard industry indexes with good market liquidity.
- EVA is not concerned that SW Gas may rely on NYMEX based pricing, as this is the leading price benchmark of the U.S. natural gas industry, and it cannot be avoided. Furthermore it should continue to be at Southwest's discretion, whether it locks fixed prices for the APSP in either one or two transactional components.
- While it would be to the benefit of all market participants to have a larger number of transactions reported to industry publications thereby increasing liquidity of the published price indices, and theoretically increasing their reliability, each company must be responsible to determine its own comfort level and ascertain its risks and rewards before participating in the sharing of its confidential information. Participation is not a trivial matter in today's litigious world.

- Any decision by the ACC to require utilities to report transaction data to industry publications could also have unintended consequences, and thus should be carefully examined before mandating participation. If the ACC decided to require Arizona regulated gas utilities to participate, for fairness reasons and to level the playing field, it would be important to also require regulated electric utilities to report as well.
- Many of SW Gas company policies, procedures, and strategies are insufficiently documented in official company documents. While the concepts embedded in SW Gas' policies, procedures, and strategies appear reasonable and prudent, curiously one must tend to go to the documents submitted by SW Gas to the Arizona Corporation Commission to find the most complete picture of company policies, procedures, and strategies. In addition, some policies, procedures, and strategies fall short in certain areas by their lack of documented official position on certain subjects. Subsequently five management recommendations are made and summarized below.
- The Monthly Bank Balance Statements compare well to the base transactional data of the GTS, with the exception of the month of January 2007 when SW Gas under-scheduled gas commodity by 356,000 mmBtu. A number of subsequent events and actions by SW Gas, discussed in detail in Chapter 3 Section on Bank Balance Statements, suggest a similar scenario is highly unlikely to be repeated in the future. Still SW Gas should continue to press EPNG to improve the quality of its 'real time' load estimates that it broadcasts to shippers via EPNG's Electronic Bulletin Board.
- SW Gas did a good job of following its policies and procedures based on EVA's Audit of Selected Transactions described in detail in Chapter 3. However as a result of this audit, EVA has an additional five management recommendations for improvement that are summarized below.

Recommendations

EVA has a total of fifteen recommendations from its review of Southwest Gas during the audit period.

EVA has five recommendations regarding Southwest's pipeline transportation and gas delivery portfolio to increase reliability and ensure that Southwest meets its commitment to serve regulated load during normal, as well during emergency operating conditions, namely:

- (1) SW Gas is attempting to diversify its interstate pipeline capacity portfolio and SW Gas should continue seeking access to storage capacity, particularly market-area storage capacity. Concerning the latter, it is suggested that the Arizona Corporation Commission take a more active role in promoting the development of market-area storage in Arizona.

- (2) SW Gas should increase the documentation and requirements for its transportation-only (T-1) customers.
- (3) SW Gas should make its Daily Forecasting Accuracy Improvement Task Force a permanent entity. SW Gas' policies should also require ongoing validation and back-testing of its daily load forecast, along with its required frequency.
- (4) Until the point that market-area storage becomes a reality in Arizona, it is recommended that the ACC develop and implement policies that would promote the sharing of gas supplies among the major users of interstate pipeline capacity in Arizona during extreme conditions, including gas LDCs and electric utilities.
- (5) While SW Gas has taken efforts to diversify its future pipeline capacity portfolio, it is recommended that SW Gas carefully track the likelihood of LNG imports entering the Southwest gas market and consider gaining access to such supplies, in an effort to diversify its gas supplies and reduce its dependence on the San Juan basin.

From the review of Southwest's policies and procedures, five management recommendations resulted and are discussed in the Policies and Procedures Section of Chapter 3 in detail. The following enhancements are suggested:

- (1) Consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.
- (2) Clarify the APSP supply element by documenting required timing and volumes for the next one to two years forward. Some companies have found the use of living appendices (to the company policies, for instance) helpful to update forward time windows and volume ranges that may change frequently. If there is uncertainty, then windows of time and ranges of volume or duration can be established instead.
- (3) Clarify the precise nature of the APSP strategy. Is it a programmatic hedge, a judgmental hedge, or a hybrid of the two? The precise strategy should be recognized and declared in company policies and procedures to guide employees and decision makers, as well as the ACC's oversight.
- (4) Designate the *Arizona Dispatch Guidelines* as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in company policies and procedures.
- (5) Company policies regarding the 'unbuying' of gas, as well as the reasons for the policies, should be reevaluated, and then explicitly documented in official company policies and procedures.

Five management recommendations also resulted from EVA's review of specific gas supply transactions. The audit methodology and the transaction selection process are

discussed in detail in the Audit of Selected Transactions Section of Chapter 3. The recommendations are:

- (1) Ensure all confirmations with gas suppliers, also known as Exhibit A, include deal transaction dates.
- (2) Ensure all confirmations with suppliers, also known as Exhibit A, include dates of the internal approval next to the signature authorization.
- (3) Considerably shorten the time lapsed between deal execution and deal confirmation with gas supplier.
- (4) Include a list of attendees present during the solicitation and purchase of the APSP fixed price gas supply element (as well as during selection and approval of the index gas supply element) to ensure independence, proper monitoring, and to improve the quality of the audit trail.
- (5) Update any old master supply agreements that cap the buyers' liquidated damages at 50 cents per mmBtu into supply agreements that are based on true-up to actual market during non-performance.

All (but one) of these management recommendations should be easy for SW Gas to implement and document in internal policies by December 1, 2008. Such a near-term date implies that Southwest Gas would be likely to implement these recommendations during the summer and autumn months of 2008 while it was purchasing gas for the next winter season of November 2008 through March 2009. These recommendations take on elevated importance and urgency given SW Gas's expected execution of its first-ever financial derivative hedges in 2008. On December 1st of each year, SW Gas submits its Arizona Annual Gas Procurement Plan to the ACC, and this seems to be a pre-existing opportunity to show compliance to the ACC.

A stickier issue is the 'un-buying' policy. At minimum, SW Gas should document its current policy by December 1, 2008. Re-evaluating this policy could take more time. EVA believes that SW Gas is being reactive to circumstances outside of its control and doing what it perceives is best for consumers. 'Unbuying' appears to be some form of a physical sale, only back to the original seller and potentially for a net settlement. It is a legitimate physical transaction, and in EVA's humble opinion, should not be considered as speculation, however Southwest Gas has the burden of proof of convincing its external auditors that it is a 'normal' transaction according to FAS 133 accounting and reporting standards. This may take some time to sort out for physical transactions. By

contrast, there is no reason to expect a legitimate need to 'unbuy' any financial derivative transactions.

2

EPNG PIPELINE DYNAMICS

Overview

Probably the most significant event during the audit period (i.e., September 2004 through April 2007) for SW Gas was the total and complete restructuring of the El Paso Natural Gas (EPNG) pipeline tariff (i.e., EPNG tariff effective January 1, 2006, subject to revision) and the impact this change has had on the East of California customers and, in particular, Southwest Gas (SW Gas). This single event appears to have had an impact on nearly every phase of SW Gas' operations during the audit period. Furthermore, it is difficult to note succinctly the enormity of this change and its impact on SW Gas. As a result this major change in the EPNG tariff is discussed as a separate item in this report and then cross referenced as appropriate in other sections of this report. Lastly, the concluding sections of this chapter specifically address in detail the various penalties and charges incurred by SW Gas, as a result of this new EPNG tariff.

Background

Historically, the Arizona portion of SW Gas has been dependent entirely upon EPNG for its interstate pipeline services. While, in general, the optimum strategy for a local distribution company (LDC), such as SW Gas, would be to diversify its pipeline services by connecting to two or more interstate pipelines, historically this has not been an option for SW Gas, because of the physical structure of the interstate pipeline system within Arizona.¹

¹ The likelihood that in the future Transwestern will be providing SW Gas with some interstate pipeline services is discussed in a subsequent section of this chapter.

While EPNG has a long and complex history, in rather simplified terms, the pipeline was built to bring San Juan basin gas (i.e., mostly in New Mexico) to Southern California. In order to accomplish such a goal, the EPNG needed to transverse the state of Arizona. In order to gain the cooperation of the various stakeholders in Arizona, EPNG offered to provide various gas buyers all of their required gas loads. At the time these gas buyers were primarily various relatively small communities and cities, some of which were served by SW Gas. These contracts that provided the various Arizona customers with all of their gas requirements came to be known as full requirements contracts. Under these full requirements contracts the Arizona customers were, in essence, charged for the amount of gas they consumed, but were allowed to vary their daily gas usage from minimum load requirements (i.e., usually in the non-winter months) to peak load requirements (i.e., usually during the coldest part of the winter) at no additional charge. In colloquial terms within the industry, this is referred to as 'free swing' capability.²

Initially, this approach worked reasonably well as the Arizona loads were relatively small in comparison to the California loads. For example, during the mid-1980's Arizona gas loads were less than seven percent of California gas loads.³ However, by 2004 because of the significant growth of the Arizona gas market, this relationship changed such that Arizona was 14.5 percent of California's gas loads.⁴

The key factor behind this growth in the Arizona market was the increase of gas requirements for the electric power sector. Between 1995 and 2004 gas consumption for the electric sector within Arizona increased by a factor of 12 (i.e., from 19 to 240 BCF), as during the building boom for gas-fired capacity Arizona installed over 9,200 MW of new gas-fired capacity.^{5,6}

² The East of California customers will argue that these swing services were not free, but rather part of what was contracted for under the full requirements concept and thus, a service for which they paid. Reviewing such an argument and its legal connotations is beyond the scope of this report.

³ Technically, the comparison should be to Southern California gas loads, which would yield a higher fraction. However, comparable data for Southern California is not readily available. In addition, the basic trend would remain the same.

⁴ A similar assessment would apply to relative loads on the EPNG system, except that the fraction would be higher. Comparable data for the EPNG system is not readily available.

⁵ The building boom for gas-fired capacity was from 1999 to 2004 when the U.S. power industry installed over 204 GW of new gas-fired capacity.

⁶ During the 1995 to 2004 period Arizona's residential, commercial and industrial loads also grew, but at only 1.2 percent per annum rate.

From the perspective of an interstate pipeline, the growth in Arizona's electric gas loads was particularly problematic, as gas loads tend to be very seasonal⁷ and, in particular, daily gas burns tend to be concentrated within a few hours of the day. Concerning the latter, it is not uncommon for a gas-fired power plant to consume its entire daily gas requirements in a six to eight hour period. The situation for gas-fired peaking units is even more dramatic, as the peaking units can consume their entire daily load requirements in two to four hours. These are very difficult load profiles for an interstate pipeline, particularly when similar load profiles exist at the same time for a number of plants.⁸

The net result of the combination of (1) the growth in Arizona gas loads, (2) the load concentration within the power sector and (3) the typical load profiles of gas-fired power plants, resulted in EPNG no longer being able to offer 'free swing' services to its Arizona customers, particularly in light of the magnitude of the cumulative 'free swing' services required by the Arizona customers. In effect, providing 'free swing' services of this magnitude would force the pipeline to operate outside an acceptable and safe range. In theory, the pipeline could be forced to exceed either its maximum operating pressure (MAOP) or its minimum operating pressure in order to provide these swing services. The other alternative, in essence, would be a significant system expansion in order to meet peak hour load requirements. Lastly, the use of market area natural gas storage would help alleviate the lack of swing services on the EPNG system, however none exists within Arizona.⁹ As a result, the full requirements approach that existed for so long in the Arizona community had to be replaced with a different approach.

EPNG Rate Case

While the history of the 2005 EPNG rate case is long and complex,¹⁰ in very simplified terms EPNG went to its major California customers and presented a case that the EPNG system could no longer operate under the full requirements concept used for the East of California customers and that it should not propose a major expansion of the system, which would increase pipeline rates for all customers.¹¹ The California customers

⁷ About 25 percent of Arizona's annual electric power gas consumption occurs during the two summer months of July and August, which primarily is required to meet the state's air conditioning load.

⁸ Arizona's gas load requirements for the power sector are dominated by 20 new gas-fired combined cycle units and seven new gas-fired simple cycle units (i.e., peakers).

⁹ The subject of natural gas storage is further discussed in a later section of this report.

¹⁰ See the Appendix for a chronology of events.

¹¹ Because of their access to large amounts of natural gas storage inside the state of California, the California customers, in essence, do not require the use of the full requirements approach. Thus, the

concurred and the combination of EPNG and the California customers then proceeded to convince the FERC staff that a major change was required. EPNG then presented its new rate case, which basically already had been endorsed by the California customers and the FERC staff, to its customers. What followed was a long and drawn out rate case proceeding that involved a major change to how the EPNG system was operated and, in essence, pitted California customers against the East of California customers.

While the operational concept of providing 'free swing' services and thus, the full requirements approach had to come to an end because of the type of growth on the EPNG system, in the viewpoint of some industry observers, including the authors of this report, the effective trade of full requirements contracts for the East of California customers for the pipeline services provided under the new EPNG tariff was not very equitable. Nevertheless, the East of California customers were forced to adapt to an entirely new set of pipeline services on the EPNG system. The enormity of this change, along with the tension between the EPNG and its customers, as well as between classes of customer, cannot be understated. Similarly, the uncertainty over details of how the new EPNG tariff approach would affect various customers and the problems/flaws of what was proposed by EPNG cannot be understated.¹²

In very simplified terms what EPNG proposed for the East of California customers was to convert its system from (a) a full requirements concept that did provide swing services to (b) a system that, in essence, provided no swing services.¹³ This new approach as originally proposed, in essence, requires a customer to take daily gas requirements evenly over the entire day (i.e., $1/24^{\text{th}}$ of the daily requirements each and every hour) without any variance, and any such variances result in additional charges or penalties.¹⁴

California customers were not interested in expanding the EPNG system, particularly when such an expansion would, in essence, be for the benefit of the East of California customers.

¹² The 2005 EPNG rate case may be both (a) the most significant transition ever for an interstate pipeline and (b) one of or the most arduous and contested interstate pipeline rate cases. The only interstate pipeline rate case in the view of the authors of this report that might be comparable would be the Florida Gas Transmission rate case, in the 1990s. In the FGT rate case it was finally agreed to, in essence, split the system into two non-divisible halves, with the first half serving historical customers at a relatively low pipeline tariff, and the second half serving new customers at a relatively high pipeline tariff.

¹³ While the purpose of this report is to provide a broad overview of the transition for the East of California customers, technically the full requirements era came to an end in September 2003.

¹⁴ While no pipeline can provide infinite swing services, other major interstate pipelines have allowed for some swing capability. The Columbia Gas Transmission system, while designed for even hourly gas flows, allows hourly capacity to be 120 percent of even hourly gas flows. Other interstate pipelines have used the '6-percent rule' for hourly gas flow. Under this concept hourly gas flows can be 6 percent of total daily requirements, which mathematically works out to 144 percent of even hourly gas flow. See EPRI, *Natural*

Exacerbating this basic phenomenon of no swing services on the EPNG system was that the concept was extended to every D-code, meter and contract, which on a practical level, creates an operational nightmare for a customer such as SW Gas.¹⁵

In order to avoid such charges and penalties the customer had the alternative to subscribe to a set of premium services, which were (a) very expensive, (b) relatively complicated and (c) very restrictive in their requirements. Concerning the latter, even with the utilization of such premium services a customer still could be subject to penalties.¹⁶

From a customer's perspective, and in particular, a local distribution company, such as SW Gas, it is literally impossible to operate (i.e., meet the needs of their customers) without any swing capability. The primary reason for the latter is the behavior of residential customers, which have peak consumption requirements during the hours they are awake and very limited requirements while they are asleep.¹⁷ A similar phenomenon exists for commercial and industrial customers.

Response By Southwest Gas

Overview

The response by Southwest Gas to the new EPNG tariff is reviewed in the material below. While SW Gas took a number of actions to limit its exposure to additional charges and penalties, SW Gas nevertheless incurred approximately \$6.7MM in additional charges and penalties during the audit period, before any refunds.¹⁸ The

Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination, (TR-101239), September 1992, Chapter 2.

¹⁵ For clarity if there are six supply contracts delivering to a meter and four meters within a D-code, in essence, there can be zero variance from the 1/24th the load concept at any of these points even though the net downstream flow from the D-code may be perfectly in balance.

¹⁶ A case in point is the FTH-3 premium service (i.e., firm transportation with three hours of swing). Under the FTH-3 premium service the customer is allowed to have an hourly burn that is 150 percent greater than its average daily burn, which is not an uncommon occurrence, for up to three hours during the day, but the three hours must be consecutive. Variation from either the 150 percent criterion or the three consecutive hour criterion results in a penalty. This is the least costly of the premium services, as it is only about seven percent more expensive than the standard no variance FTH-1 service, which in turn was priced about 10 percent above similar historical services. The next level of premium services (i.e., FTH-8) cost almost 70 percent more than the FTH-1 service.

¹⁷ Even during the hours when a residential customer is awake there is a significant variance in their hourly consumption patterns.

¹⁸ The total amount of additional charges and penalties before any refunds is highlighted in this report in order to provide the reader with a complete perspective of what occurred during the audit period and the net result of subsequent actions by SW Gas and other East of California customers. One of the final sections of this chapter addresses refunds during the audit period.

following assessment of these charges and penalties is divided into two sections, namely (a) those charges and penalties associated with a relatively unique force majeure situation that existed during the November 30, 2006 to December 4, 2006 time frame (i.e., approximately \$3.4MM) and (b) other charges and penalties during the audit period (i.e., approximately \$3.3MM) – again before refunds.

Other Charges And Penalties¹⁹

Background

The three most significant characteristics of the new EPNG tariff for East of California customers were the following:

- (1) **The Magnitude of Change:** The enormity of the operational changes under the new tariff simply cannot be understated. SW Gas and the rest of the East of California customers simply did not have any prior experience upon which to make optimal decisions concerning the selection of new pipeline services.
- (2) **Uncertainty:** Through the initial period of the new EPNG tariff (i.e., the period of the initial proposal through initial implementation, or most of 2005) there was significant uncertainty over both (1) the cost of the new pipeline services²⁰ and, in some cases, the definition of those services and (2) the implementation of the various additional charges and penalties (i.e., the how and when). The former significantly impeded any effort to minimize overall cost, while the latter made it almost impossible to assess the economic tradeoff between subscribing for a set of premium services and the potential for additional charges and penalties with or without such premium services.
- (3) **Flaws:** EPNG in its new pipeline tariff proposed an entirely new operational concept, which subsequent events would prove had a number of flaws – some of which were significant. For the most part these flaws occurred because of EPNG's objective of carrying out the 'no swing service' concept to the smallest divisible unit (i.e., to individual D-codes, meters and contracts) on its system.²¹ The operational problems and inequities caused by these flaws, as well as the incorrect data, were the subject of intense discussions between SW Gas and

¹⁹ For purposes of this report the phrase 'other charges and penalties' refers to all those additional EPNG charges and penalties incurred by SW Gas during audit period, except those charges and penalties during the cold weather or force majeure event that occurred between November 30, 2006 and December 4, 2007.

²⁰ The major new EPNG pipeline services included the following firm services FTH-1 (i.e., firm service with no swing capability) and a series of firm premium services, such as FTH-3, FTH-8, FTH-12, FTH-16, NNTH-3 (i.e. no notice), NNTH-12, and NNTH-16. Most of these new premium services had unique and rigid definitions and requirements – some of which were counter intuitive. Also, included in the new tariff were interruptible services (IT-1 and IHSW-1) and the use of a new scheduling service, referred to as HEEN (hourly enhanced entitlement nomination).

²¹ The original EPNG proposal for SW Gas included several delivery points that had been abandoned and excluded at least five relatively new taps. These are relatively simplified examples of flaws contained in the original EPRI proposal. Other more complex flaws required the use of hydraulic modeling to fully correct them. Nevertheless, correcting each of these flaws was important to SW Gas in order to minimize other charges and penalties.

EPNG both during the initial review period and subsequent to the implementation of the tariff.

The combination of these three characteristics of the new EPNG tariff left SW Gas in an environment where it (1) had no operational experience with this new and very complex system, (2) did not have a full perspective on the costs of the various new pipeline services until after they made their initial selection of new pipeline services, and (3) lacked almost any appreciation of either the potential for penalties or their magnitude. Concerning the cost of these new services, there was a significant increase. For example, historically SW Gas paid EPNG about \$32 to \$34MM annually for its pipeline services. The initial proposal by EPNG for its new tariff would have increased the cost for a somewhat comparable set of pipeline services to approximately \$70 to \$99MM. Through the efforts of SW Gas and other East of California customers during the review process for the proposed EPNG tariff, this latter cost was reduced to the \$50MM+ range depending upon a number of factors.

The net result was that SW Gas, in order to minimize costs, initially focused primarily on using the less costly FTH-1 service in order to meet its interstate pipeline transportation requirements. While this in hindsight left SW Gas vulnerable to additional charges and penalties, at the time the optimum economic tradeoff between the cost of pipeline services and the minimization of additional charges and penalties was probably not knowable. The rest of the East of California customers were in a similar situation and, for the most part, used a similar initial strategy in selecting a portfolio of new EPNG pipeline services. For example, none of the other Arizona customers initially selected any of the relatively expensive no-notice pipeline services, even though the use of no-notice service very likely would have minimized a customer's exposure to additional charges and penalties.

Further compounding this situation was EPNG's assignment to SW Gas, and other East of California customers, specific capacity rights from both the San Juan basin and the more expensive Permian basin using an EPNG algorithm. This approach basically precluded SW Gas from selecting the optimum set of capacity rights for its customers in that these capacity rights were assigned.²²

²² In the viewpoint of some industry observers, including the authors of this report, EPNG adopted this approach in order to ensure greater utilization of its capacity from the Permian, which on a delivered cost of

Lastly, the California customers were not subject to this predicament concerning both the uncertainty over the various premium services and the potential exposure to additional charges and penalties. This situation for the California customers existed at two levels. Operationally because of their access to considerable market area storage in Southern California, the California customers could easily take daily gas requirements on an even, hourly basis (i.e., 1/24th per hour) and use their access to market area storage to balance any variance between actual consumption levels and even hourly gas deliveries. In addition, the EPNG tariff provided an exemption from these penalties for delivery points with operating balancing agreements (OBA). On the EPNG system these OBA points were basically Topock and Ehrenberg, which is where the California customers take deliveries from EPNG.

Additional Charges And Penalties

While SW Gas' initial selection of pipeline services was reasonable at the time, it nevertheless resulted in additional charges and penalties of about \$3.3MM during the audit period (i.e., before refunds) and potentially these charges could have been larger if it were not for the proactive measures taken by SW Gas during this time frame. Exhibit 2-1 summarizes these various additional charges and penalties and identifies those that subsequently were refunded. Also, while these additional charges have been grouped together for the purpose of the assessment in this report, there are technical differences between the two categories. Probably the most significant practical difference is that EPNG retains all of the additional 'charges', while the 'penalties' are refunded to the customers. While the exact algorithm for the refunding of the penalties is complex, the basic concept is to collect penalties from those customers that exceed EPNG system tolerances and refund it back to those customers who did not exceed system tolerances. Furthermore, from a pragmatic perspective once a customer pays a penalty there is no guarantee that this customer will receive even a partial refund of that penalty. As a result, penalties, as is the case with the additional charges, in essence, represent an additional cost, hence the reason for grouping the two categories in this report. For completeness, Exhibit 2-1 identifies which categories of additional charges and penalties are retained by EPNG and which are subject to refund. The Appendix provides a more complete definition for each of these various additional charges and penalties.

gas basis is a more expensive alternative. Historically, utilization of this Permian capacity had been problematic for EPNG.

In simplified terms, EPNG invokes penalties at three different levels, namely (1) system wide daily balancing penalties,²³ (2) daily and hourly balancing penalties at individual meters (i.e., MDO and MHO) and (3) more severe penalties during critical operating conditions,²⁴ that are declared by EPNG. While on any given day a customer can incur penalties at all three levels, the actual charge is the highest of the three categories and not the cumulative amount. As illustrated in Exhibit 2-1, the daily variance penalties²⁵ and the charges at individual meters or taps (i.e., MDO and MHO), account for 75 percent of the total charges and penalties during the audit period. These items are further discussed in the material below.

Exhibit 2-1. Additional Charges And Penalties Paid By Southwest Gas During The Audit Period

Category of Charge/Penalty	Cumulative Amount of Charge/Penalty (\$000)	Retained By EPNG	Subject To Refund
Daily Variance ⁽⁶⁾	\$1,203	Yes	-
MDO ⁽²⁾ Violation Penalty ⁽⁶⁾	\$730	-	Yes
MHO ⁽³⁾ Violation Penalty ⁽⁶⁾	\$571	-	Yes
Hourly IHSW ^{(4),(6)}	\$242	-	Yes
Daily Overrun ⁽⁶⁾	\$217	Yes	-
COC Imbalance Charge	\$189 ⁽¹⁾	Yes	-
Hourly Overrun ⁽⁶⁾	\$112	-	Yes
Hourly Scheduling Penalty ⁽⁶⁾	\$58	-	Yes
SOC Imbalance Charge	- ⁽¹⁾	Yes ⁽⁵⁾	-
Emergency COC Imbalance Charge	- ⁽¹⁾	Yes	-
Subtotal	\$3,322		
Refunded Items ⁽⁷⁾	(\$1,734)		
Net	\$1,588		

(1) Excludes COC charges during the force majeure event of November 30, 2006 to December 2, 2006, which are discussed in a subsequent section of this chapter.

(2) Maximum daily overrun at individual taps.

(3) Maximum hourly overrun at individual taps.

(4) Interruptible swing service.

(5) Complex.

(6) Fully or partially refunded item.

(7) Excludes interest.

Source: Southwest Gas.

²³ This category can be divided into scheduling penalties that are authorized and daily variations that are unauthorized.

²⁴ Technically, there are two categories of critical operating conditions, namely the less severe Strained Operating Condition (SOC) and the more severe Critical Operating Condition (COC).

²⁵ After considerable effort by SW Gas and the other East of California customers these daily variance penalties eventually were refunded at the end of the audit period.

Actions By Southwest Gas

As previously noted, SW Gas has been proactive during the entire test period in taking actions to either minimize or eliminate these additional charges and penalties. These proactive efforts by SW Gas included:

- Intense efforts to have EPNG correctly assign or modify MDO and MHO levels for various taps;
- Efforts to revise various segments of the EPNG tariff; and
- Judiciously increasing the level of premium services over time.

Penalties For Individual Meters

Under EPNG's new tariff the concept of no swing capability was transferred down to the lowest possible level on the pipeline system, namely the individual meter. As a result, any variance in either daily gas loads from designated levels at an individual meter (MDO) or even hourly loads (MHO) at an individual meter resulted in a penalty under EPNG's system. In addition, the MDO and MHO levels were assigned by EPNG based upon an internal EPNG assessment that was derived from a historical usage algorithm. Subsequently, it was proven that EPNG's assessment for several meters was in error. Furthermore, this concept was extended downstream to each supply contract behind a given meter,²⁶ which made the implementation of the EPNG tariff even more complex and operationally almost a nightmare. Lastly, the concept also was applied upstream to the EPNG D-codes.²⁷ As illustrated in Exhibit 2-1, the combined MDO and MHO charges and penalties represent the largest single category of charges and penalties and account for about 39 percent of the total before refunds and 65 percent of the total after refunds.

Because of certain characteristics of the EPNG system, SW Gas, more than any other East of California customer, is affected by the MDO and MHO provisions in the EPNG tariff. This occurs because SW Gas takes gas from more points (i.e., taps) on the EPNG system than all the remaining East of California customers combined.²⁸ This unusual situation is, in large part, an artifact of the full requirements era for the EPNG pipeline.

²⁶ For example, if there were six separate supply contracts to provide gas to a given meter, then variances for each contract would be tracked and these variances could result in additional charges and penalties.

²⁷ In simplified terms a D-code is a group of meters that are usually within close geographic proximity.

²⁸ SW Gas has approximately 215 taps on the EPNG system that have active EPNG telemetry and approximately 120 taps that Southwest reads on monthly basis (i.e., charts) with this data manually provided to EPNG.

During the full requirements era, EPNG was required to meet all SW Gas gas supply requirements. As a result, when new communities emerged as part of the overall growth within the state SW Gas would need additional gas supplies at a series of new locations, and EPNG would extend its system to these new locations and provide a new tap. At the time having EPNG extend its system and incur the additional capital costs appeared to be the preferred alternative to SW Gas extending its system to connect to EPNG and incurring the capital cost. While EPNG was obligated to complete system extensions even if it involved relatively small volumes and relatively small laterals, the net result was that over time parts of EPNG began to appear more like a local distribution system than an interstate pipeline, and SW Gas had a large number of taps on the EPNG system. An alternative approach, which is common to many LDCs, is to have a series of large city gates that take gas from one or more interstate pipelines at each city gate, and then build downstream pipelines from these city gates to the various load points for the LDC. While in hindsight now that the full requirements era has come to an end, it might be considered desirable for SW Gas to have built a series of city gates and associated downstream pipelines, that is not what happened and it cannot be reversed – at least economically.

The other East of California customers are not faced with a similar situation. This is particularly true of the Arizona electric utilities, which have large point loads that only require a single tap for each point load. Furthermore, with respect to the MDOs for the taps serving electric utilities initially the values assigned by EPNG for these MDOs were based upon a historical usage algorithm, as was the case for SW Gas. Because most Arizona electric loads have grown – in some cases substantially – the assigned EPNG figure based upon historical usage was inadequate for most electric utilities (i.e., this also was true for many SW Gas taps). However, this dilemma was rectified for most of the electric utilities as a net result of the Santan pipeline²⁹ transfer. In simplified terms when Salt River transferred the Santan pipeline to EPNG, Salt River was able to secure an MDO that met the current full load requirements of its power plant site.³⁰ Subsequently, EPNG, in order not to discriminate among electric utilities, allowed most of the electric utility MDOs to reflect the current full load requirement of the various power plant sites. The same was not done for SW Gas and, as a result, there is a

²⁹ Also referred to as the East Valley Lateral.

³⁰ See Docket No. RP05-422-024, Protest of Southwest Gas Corporation of El Paso MDO Procedures Compliance Filing, January 28, 2008.

significant disparity among the East of California customers with respect to EPNG's MDO provisions.³¹

The combination of SW Gas being uniquely affected by EPNG's MDO and MHO provisions and its overall desire to minimize additional charges and penalties has led SW Gas to vigorously pursue correcting various flaws in EPNG's overall process of assigning MDO levels and changing MDO levels wherever possible to represent current SW Gas load conditions.

The number of actions taken by SW Gas on this matter is difficult to summarize because of both the large number of actions and the enormous variety of actions taken, as the circumstances for the nearly 335 SW Gas taps tend to be site specific. In general, this process requires SW Gas to identify flaws with EPNG's MDO/MHO provisions and make a filing with EPNG for a correction and/or a waiver of penalties. Each action can be a rather lengthy process as (1) the burden of proof is on SW Gas, (2) hydraulic modeling of the EPNG system is required in some cases, (3) the request and supporting information usually has to be reviewed verbally with the EPNG staff, (4) a formal request must be filed with EPNG and (5) a formal response must be received from EPNG.

With respect to the large number of actions taken by SW Gas, its Planning Department maintains a three-inch notebook, which is nearly full.³² The material in this notebook documents each of the requests made to EPNG on the MDO/MHO provisions and the resulting outcome. To date SW Gas has been successful in obtaining MDO/MHO increases at approximately 145 metering points, which has been a significant factor in minimizing future charges and penalties. Exhibit 2-2 provides highlights for a few of these actions.

As a practical matter while the charges and penalties associated with EPNG's MDO/MHO provisions have been reduced by various actions by SW Gas, in the future it is highly unlikely they will go away for SW Gas. This assessment is based upon the following factors, some of which are unique to SW Gas.

³¹ See FERC Order Dismissing Requests for Rehearing and Clarifying MDO Procedures issued December 20, 2007.

³² See *Southwest Gas/EI Paso Natural Gas MDO/MHO*, which is retained by Southwest Gas' Planning Department.

Exhibit 2-2. Selected Example Of Southwest Gas' Efforts To Minimize MDO/MHO Penalties

Description	Location	D-Code/Meters
<ul style="list-style-type: none"> Corrected MDO and MHO levels that were incorrect.⁽¹⁾ 	North Loop Substation and Ft. Huachuca	Meter No. 31682 in D-Code 475643 (DSWGN78) and Meter No. 31692 in D-Code 475585 (DSWG HCH)
<ul style="list-style-type: none"> Requested shifting MDO rights in order to resolve apparent deficiencies on the EPNG system that resulted in penalties during January 2007 and that these penalties be waived. Basically a request to allocate unutilized MDO/MHO rights from a downstream meter to an upstream meter under the 'walk the pipe' concept.⁽²⁾ 	Bell Road City Gate, Glendale City Gate, Lateral 25 City Gate	Meter Nos.: 31656, 30433, and 30249.
<ul style="list-style-type: none"> Requested revision to peak-day requirements for SW Gas on EPNG system at individual meter levels. Required submittal of 2,748 data points. Request five relatively new taps, excluded by EPNG, be added.⁽³⁾ 	Entire System	New taps: Robson, Red, New Whetstone, Arivaca Junction, and 7E.
<ul style="list-style-type: none"> Notified EPNG that because of maintenance a meter would be out-of-service and loads would shift to a second meter. SW Gas still incurred penalties despite notification. Subsequently, SW Gas requested a waiver of penalties, which EPNG granted after performing hydraulic modeling which indicated that the requested shift in loads had a positive effect.⁽⁴⁾ 	Duval City Gate	Meters No. 30657 and No. 31524 in D-Code 216811 (DSWG TUS).
<ul style="list-style-type: none"> Submitted bid for additional MDO/MHO levels and challenges requirement to demonstrate 'nameplate maximum burn capability' (i.e., requirement), which primarily pertains to electric generators.⁽⁵⁾ 	Numerous	Numerous.
<ul style="list-style-type: none"> Requested notification of hardware modification in order to obtain at least meter capacities equivalent to EPNG's original MDO allocations.⁽⁵⁾ 	Numerous	Meter Nos.: 20-003, 20-006, 20-019, 20-024, 20-103, 20-105, 20-142, 20-353, 20-427, 20-496, 20-528, 20-594, 20-612, 34-719, and 34-806.

Exhibit 2-2. Selected Examples Of Southwest Gas' Efforts To Minimize MDO/MHO Penalties

Description	Location	D-Code/Meters
<ul style="list-style-type: none"> Requested a combination of D-codes in close proximity in order to better reflect system flow requirements.⁽⁵⁾ 	Yuma Lateral	DSWG-N78 and DSWG-578; DSWG YUM, DSWG COG, DSWG YIR, and DSWG WIL.
<ul style="list-style-type: none"> Requested a change to the MDO/MHO among various delivery points and an increase at another delivery point in order to better represent system operations. While the change was granted, SW Gas still received penalties and subsequently had to seek a waiver.⁽⁶⁾ 	Chandler No. 1 and Foothills Club	Meters No. 30029 and 34790 in D-Code 216808.
<ul style="list-style-type: none"> Increased MDO/MHO levels for meters in the Tucson area in order to more accurately reflect area growth and current load conditions.⁽⁷⁾ 	Tucson, AZ	Meters No. 30148, 30149, and 31518.
<ul style="list-style-type: none"> Increased MDO/MHO levels for meters in the Phoenix area in order to more accurately reflect area growth and current load conditions.⁽⁸⁾ 	Phoenix, AZ	Meters No. 30249, and 30433.
<ul style="list-style-type: none"> Requested hydraulic modeling for potentially constrained laterals and other areas in order to identify where MDO rights can be increased without impairing system operations and what capital improvements might be required to alleviate such constraints.⁽⁹⁾ 	Numerous	Numerous

(1) See EPNG Notice ID: 6489.

(2) See Steve Williams memorandum dated January 29, 2007.

(3) See Richard Jordan memorandum dated December 30, 2006.

(4) See EPNG Notice ID: 6440.

(5) See Steve Williams memorandum dated May 31, 2006.

(6) See EPNG Notice ID: 6577.

(7) This is the net result of a relatively long and drawn out process from May 2006 to December 2007. On average this resulted in a 50 percent increase.

(8) This is the net result of a relatively long and drawn out process from May 2006 to December 2007. On average this resulted in a seven percent increase.

(9) See Richard Jordan memorandum dated June 18, 2007.

- **Large Number of Taps:** SW Gas has a very large number of taps, which among East of California customers is a feature unique to SW Gas.
- **Current Load Profile:** EPNG's historical usage algorithm does not reflect SW Gas' current load profile at many of its taps and SW Gas was not granted relief on this matter, which was done for the East of California electric utilities.
- **Reticulated System:** Portions of the EPNG system are reticulated, consequently loads between meters can shift, as a result of changing pressure in other parts of the EPNG system. While SW Gas has no influence on such system pressure changes and the net downstream result is that the scheduled amount of load is unchanged, under EPNG's rigorous accounting oriented MDO/MHO provisions SW Gas will still incur a penalty for that meter which had higher than expected loads, and no credit for the meter with lower than expected loads, even though the two variances are offsetting.³³

EPNG Tariff Revisions

In addition to representing a major change in operational requirements, the new EPNG tariff as originally proposed has been very difficult to implement for the East of California customers and, in particular, SW Gas. SW Gas has been an active participant, and in some cases the leading participant, in attempting to revise the new EPNG tariff to reduce the difficulty in implementing it, to minimize its operational complexity and to reduce the exposure to additional charges and penalties. While a thorough discussion of these actions and a detailed examination of some of the relatively technical issues involved in such actions is beyond the scope of this report, SW Gas has been very active in the regulatory arena in seeking revisions to the EPNG tariff. This has involved active participation in technical conferences, as well as rate case settlement discussions. Some of the results to date include:

- The creation of the 'dead band' for hourly scheduling, which helps minimize other charges and penalties;³⁴
- The elimination of daily variance and hourly overrun penalties;³⁵
- The revisions of definitions for SOC and COC conditions, as well as critical parameters for these conditions (e.g., minimum and maximum line pack);
- The rejection of EPNG's proposed set of non-critical condition penalties;³⁶
- The ongoing efforts to establish firm rights to the meter;³⁷

³³ This two meter example is a relatively simplified example. Under actual operating conditions the variances caused by other operating conditions in a reticulated system can be relatively complex and involve several meters. Furthermore, hydraulic modeling may be required to fully quantify the impacts.

³⁴ The 'dead band' concept creates a tolerance level for hourly scheduling of 200 Dth or 13 percent, whichever is higher.

³⁵ These are the penalties that were refunded at the end of 2007.

³⁶ See Docket No. RP07-511.

- The creation of the MDO transfer concept, which helps minimize MDO/MHO charges and penalties;³⁸ and,
- The ongoing efforts to have the flow requirements for meters in reasonable close proximity to be treated as a group rather than individually.

These actions are in addition to SW Gas' continuing efforts to proactively notify EPNG of maintenance conditions in order to avoid penalties and to continue hydraulic modeling in an effort to enhance EPNG's assessment of constrained lateral systems.

Premium Services

Another area that SW Gas has pursued in order to minimize charges and penalties is the judicious increase in the utilization of EPNG's more expensive premium services. When these premium services were first proposed by EPNG there was uncertainty over their exact cost and SW Gas had no relevant experience to assess the economic tradeoff between (1) the higher cost for these premium services and (2) the potential cost of additional charges and penalties. Once SW Gas had some operational experience with the new EPNG tariff, it was able to assess the likelihood and magnitude of the additional charges and penalties, and thus, the economic tradeoffs.

Exhibit 2-3 places into perspective the cost for EPNG's pipeline services over the audit period.

As illustrated in Exhibit 2-3, historically SW Gas paid EPNG for its pipeline services about \$33MM. Based upon EPNG's initial proposal for its 2005 rate case the cost of these services would have increased by a factor of two to three times, with the upper end of the range based upon the assumption that all future pipeline services would be the premium no-notice services. There was considerable uncertainty over the final rates for the various services contained in the initial 2005 EPNG rate case. As a result, Category III in Exhibit 2-3 provides a better indication of what likely was expected for 2006 (i.e., about \$54 million). A key attribute of this Category III estimate is that it assumes no premium services and it results in about a 65 percent increase in total pipeline fixed charges over what had been paid historically.

³⁷ See Docket No. RP05-422.

³⁸ See Docket No. RP07-707.

Exhibit 2-3. Historical Perspective On Southwest Gas' Costs For Pipeline Services

Category	Cost of Basic EPNG Services (Million \$)
I. Actual 2005 annual fixed cost prior to placing into effect on January 1, 2006 the rates emanating from the 2005 rate case filing.	\$32.6
II. Estimated annual fixed costs based upon the initial proposal for the 2005 rate case.	\$70 to \$99 ⁽¹⁾
III. Estimated 2006 annual fixed costs assuming no FT-1 conversions and the loss of SW Gas legacy contracts. ⁽²⁾	\$53.9
IV. Estimated 2008 annual EPNG fixed charges after 1st conversion to FTH-3 hourly service. ⁽³⁾	\$52.0
V. Hypothetical 2008 annual EPNG fixed charges after 2 nd conversion to FTH-3 and FTH-8 hourly services. ⁽³⁾	\$53.1
VI. 2008 annual EPNG fixed charges after actual conversion to FTH-3, FTH-8 and NNTH-3 hourly. ⁽³⁾	\$54.5

(1) The higher figure reflects converting all existing FT-1 contracts to NNTH-3 (i.e., no-notice) contracts.

(2) Legacy gas contracts are Article 11.2 vintage rate capacity.

(3) Based upon Settlement rates.

Source: Southwest Gas.

The Category IV figure in Exhibit 2-3 (i.e., \$52 million) estimates what would be the 2008 fixed charges to EPNG and reflects SW Gas' first conversion to some premium services. Subsequently, as part of the second conversion,³⁹ SW Gas added some additional premium services, which increased the overall estimate of the cost for 2008 to about \$53MM (i.e., Category V). Lastly, SW Gas is now testing the use of some no-notice service in its portfolio of pipeline services which will raise the estimate for 2008 to about \$54.5 MM (i.e., Category VI). This is about 4.8 percent higher than the initial estimate provided for 2008 (i.e., Category IV), but it does include more premium services. Concerning the addition of some no-notice premium services for 2008, SW Gas' current plan is to use this service for approximately a year and then to determine if the additional cost is commensurate with its benefit, namely the capability to further reduce the other charges and penalties.

³⁹ As part of the Settlement with EPNG the East of California customers were allowed to convert the initial pipeline services they selected in the 2005 rate case at very specific points in time, which were referred to as the '1st conversion' and '2nd conversion'.

With respect to the unit cost of the various pipeline services included in the various categories contained in Exhibit 2-3, Exhibit 2-4 notes the unit costs for the various pipeline services incorporated in Categories III through VI.

Force Majeure Penalties

Overview

The largest category of charges and penalties were those that were incurred during the November 30, 2006 to December 4, 2006 time frame, when well freeze-offs in the San Juan basin resulted in producers curtailing supplies under force majeure provisions in their supply contracts. While the specific events for this time frame are a little complex, the end result for SW Gas was that it was assessed \$3.4 MM in penalties by EPNG as a result of this event.

Background

While temperatures had been relatively mild for most of November, a cold front quickly moved through the Southwest at the end of November. As illustrated in Exhibit 2-5, this cold front caused temperatures in the San Juan basin to decline about 42°F in approximately 40 hours, with about 60 percent of the temperature decline occurring in the last 18 hours. At the low point temperatures in the San Juan basin reached 5°F.⁴⁰

This decline in temperature caused a loss of production in the San Juan basin, which occurred as a result of the condensate in the gas stream freezing and then plugging flow lines. As illustrated in Exhibit 2-6, average daily flows out of the San Juan basin into the EPNG system were reduced approximately 0.5 BCFD between November 28 and November 30, 2006. As a point of reference, reductions in supply to the EPNG system from the Permian basin were about 0.4 BCFD. By comparison the absolute temperature in the Permian basin, while having declined significantly, only reached 24°F at its low point.

This loss of supply from the San Juan basin caused linepack on the EPNG system to drop dramatically and exceeded the low threshold point for strained operating conditions (SOC), as illustrated in Exhibit 2-7. This placed the EPNG system in a critical operating condition (COC), which is a very serious event for any pipeline.

⁴⁰ A similar phenomenon occurred in the Permian basin, where temperatures declined about 48°F in approximately 16 hours, but the low temperature was only 24°F.

Exhibit 2-4. Unit Costs For Selected EPNG Pipeline Services

Category III

	Annual Billed Quantity (MDth)	Effective Rates as of Jan. 1, 2006 (subject to refund) Unit Cost (\$/Dth)
Actual 1/1/06 CDs		
Legacy 11.2.a contract	2,045	9.3637
FT-1 Block	780	9.3637
FT-1 Exp	2,014	9.3637
FT-1 1903	892	9.6931

Category IV (Conversion 1)

Actual Nov. 2006 – Oct. 2007 CDs	Quantity (MDth)	2008 Rates (\$/Dth)
Legacy 11.2.a contract	2,363	8.4659
FT-1 Block	780	9.2071
FT-1 Exp	608	9.2071
FT-1 1903	704	9.6786
FTH-3	1,261	9.8398
FTH-8	0	15.5095

Category V (Conversion 2)

Proposed Nov. 2007 – Oct. 2008 CDs Without NNTH-3	Quantity (MDth)	2008 Rates (\$/Dth)
Legacy 11.2.a contract	1,981	8.4659
FT-1 Block	361	9.2071
FT-1 Exp	608	9.2071
FT-1 1903	442	9.6786
FTH-3	2,276	9.8398
FTH-8	48	15.5095

Category VI (Add NNS)

Actual Nov. 2007 – Oct. 2008 CDs With NNTH-3	Quantity (MDth)	2008 Rates (\$/Dth)
Legacy 11.2.a contract	1,981	8.4659
FT-1 Block	361	9.2071
FT-1 Exp	608	9.2071
FT-1 1903	442	9.6786
FTH-3	1,026	9.8398
FTH-8	48	15.5095
NNTH (for FTH-3)	1,250	10.9196

**Exhibit 2-5. Hourly Temperatures At Four Corners Regional Airport,
Farmington, NM – November 28-December 2, 2006**

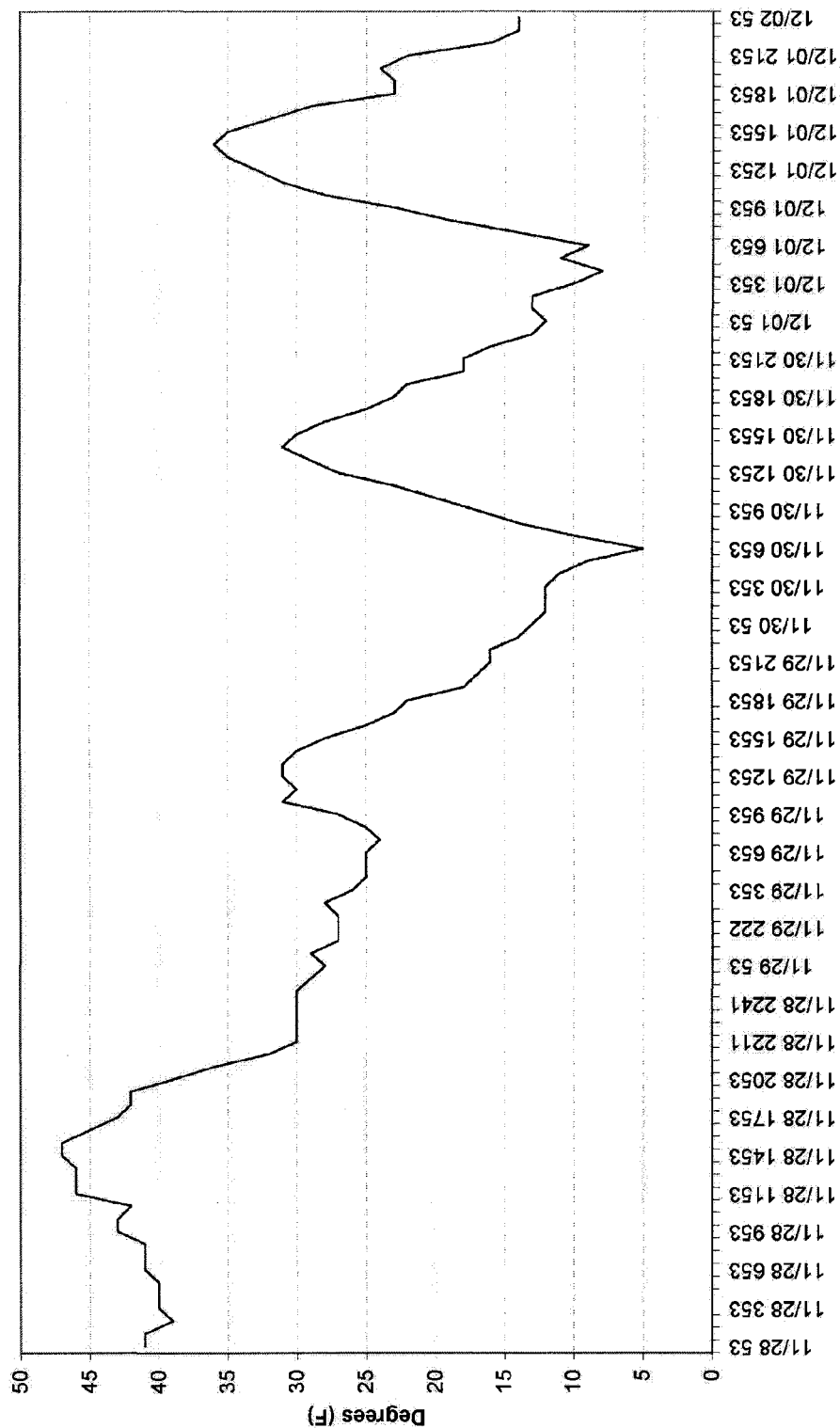
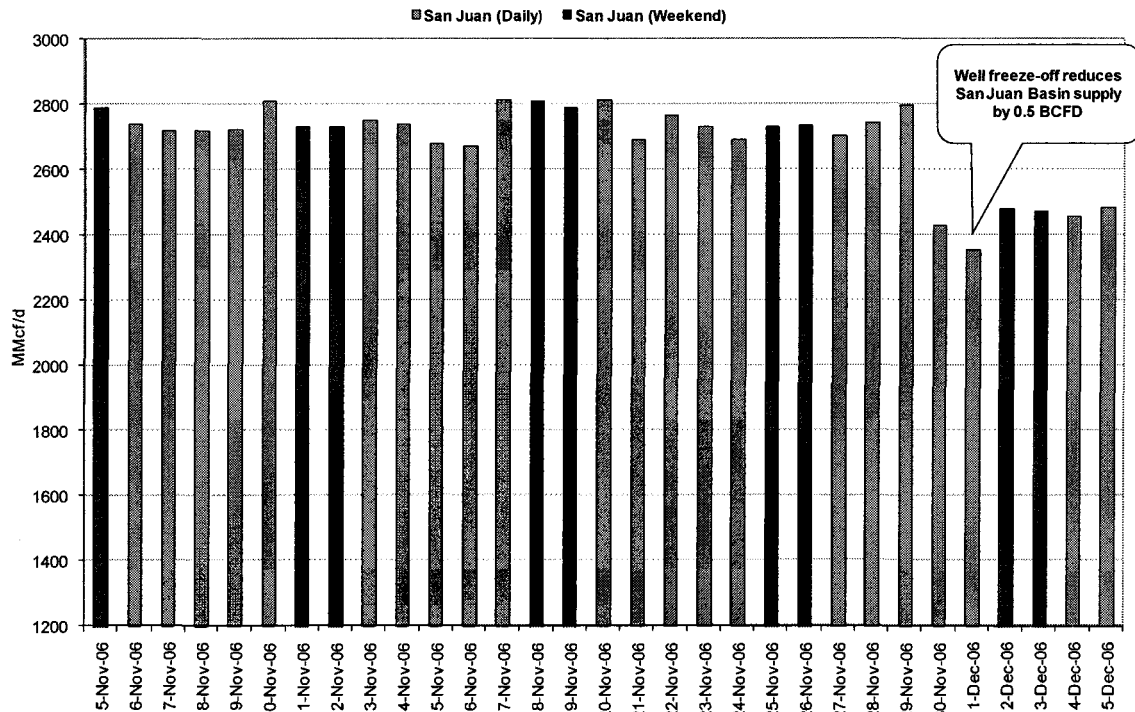
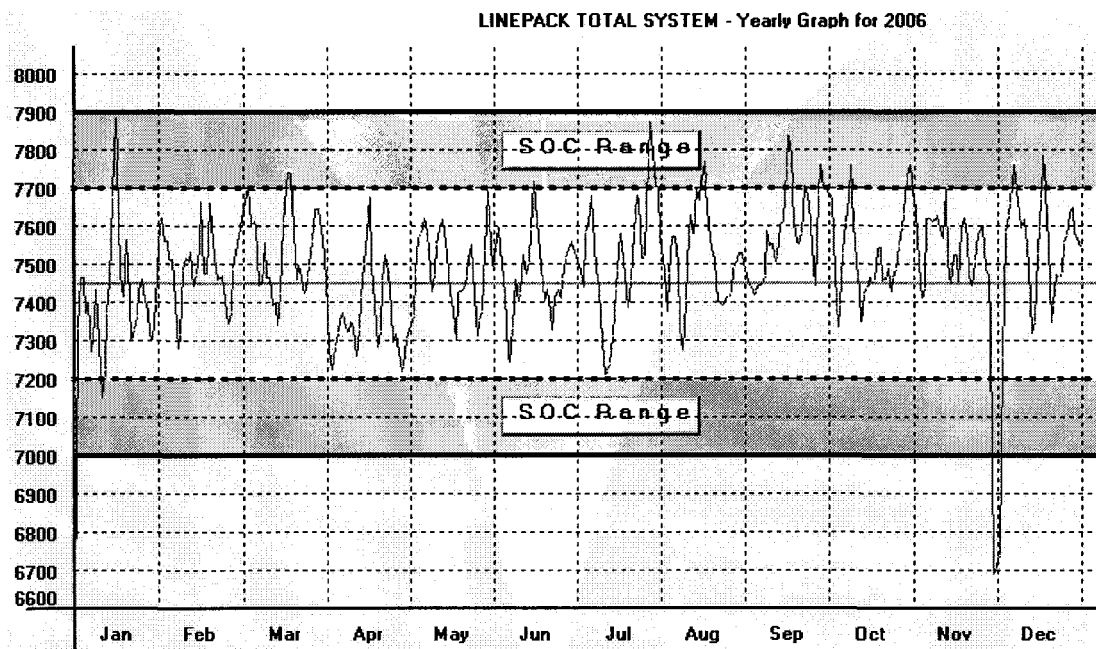


Exhibit 2-6. El Paso Natural Gas Historical Activity



Source: Lippman Consulting.

Exhibit 2-7. El Paso Natural Gas Linepack



Source: FERC Docket No. RP07-511-000, Notice of Intervention and Protest of the Arizona Corporation Commission, Exhibit 1, July 2007.

The speed at which these events occurred – namely the decline in temperature, the loss of San Juan production and the decline in EPNG linepack – appears to have caught almost everyone involved within the southwestern gas industry by surprise.

This rapidly moving cold wave also impacted the major load centers for SW Gas, which in turn caused gas demand to spike. As illustrated in Exhibit 2-8, temperatures in Phoenix declined about 18°F in approximately 15 hours to just above freezing, while in Tucson the temperature declined about 28°F in approximately 15 hours to below freezing (i.e., about 27°F).

Impact On Southwest Gas

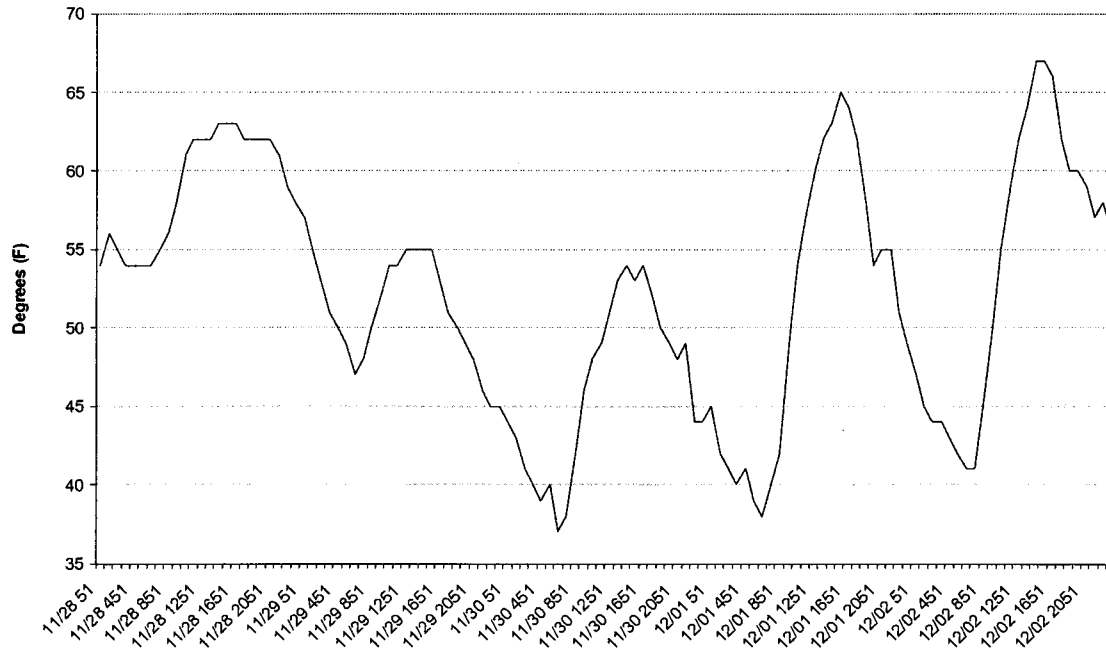
The net result on SW Gas of this rapidly moving cold front was (a) that gas demand spiked well beyond forecasted volumes and (b) producers in the San Juan basin invoked force majeure provisions after Southwest Gas had scheduled its gas supplies. Under the rigid requirements of the new EPNG tariff this resulted in SW Gas being assessed \$3.4 MM in penalties, although the figure could have been higher (i.e., about \$7 MM) if it had not been for earlier proactive initiatives by SW Gas and other East of California customers. In addition, subsequent initiatives would have had the net effect of reducing these penalties about 85 percent if the same set of conditions were to occur today. The various components of this event are discussed as separate items in the following material.

Forecasting And Scheduling Loads

While the primary driver of the subject penalties was the lost production due to the well freeze-offs, load forecasting and scheduling were a part of the overall set of events that occurred during this time frame. Exhibit 2-9 summarizes the various forecast, nomination and scheduling events for November 30, 2006. As illustrated, actual consumption by SW Gas customers on November 30 was approximately 28 percent, or 108,000 Dth, greater than the initial forecast for that day.

Exhibit 2-8. Temperature Profile For Major Southwest Gas Load Centers

Hourly Temperatures
Sky Harbor International Airport, Phoenix AZ
Nov. 28 - Dec. 2, 2006



Hourly Temperatures
Tucson International Airport, Tucson AZ
Nov. 28 - Dec. 2, 2006



Source: NOAA.

Exhibit 2-9. Summary Of Gas Loads During The Force Majeure Event

Description	Amount (000 Dth)	Date	Hour	Temperature (°F)		
				Phoenix	Tucson	San Juan Basin
Initial Forecast	380	11/28	-	54-63	43-68	39-51
		11/29	-	45-57	44-57	27-41
Preliminary Nomination	397					
Scheduling						
Cycle 1	341	11/29	9:30 a.m.	51	52	26
Cycle 2	341	11/29	4:00 p.m.	55	55	28
Cycle 3	392	11/30	8:00 a.m.	38 ⁽¹⁾	27 ⁽¹⁾	10 ⁽¹⁾
Cycle 4	417	11/30	3:00 p.m.	54	50	31
Final Schedule	334					
Final Used	488					

(1) Low temperature for Phoenix occurred at 7:00 a.m. (37°F); for Tucson at 6:00 a.m. (21°F); and for the San Juan basin at 7:00 a.m. (5°F).

Source: Southwest Gas memorandum from Larry Black dated January 30, 2007 and NOAA.

While it may be difficult to chastise SW Gas management for this disparity in light of the rapidly changing weather conditions, no LDC likes to see actual consumption exceed forecasted levels by 28 percent, even under adverse weather conditions. This includes SW Gas, which subsequently set up a multi-department task force⁴¹ to both audit the events of this period and investigate ways of improving its forecasting system. As a result of this task force the following actions were taken:

- **Weather Services:** Historically SW Gas had subscribed to a single weather forecasting service. Starting in 2007 it began subscribing to two weather forecasting services in order to obtain an additional viewpoint on the outlook for weather even though this is an additional expense. A key feature of the additional weather service is that it provides two updates to its initial weather forecast for a given day. The historical weather service only had provided a single weather forecast for each day.
- **GasDay Model:** SW Gas contracted with Marquette University to investigate and make improvements to the GasDay model that was applicable to SW Gas.

⁴¹ The Daily Forecasting Accuracy Improvement Task Force was established in December 2006 and consisted of members from Staff Engineering, Central Gas Dispatch, Gas Purchases and Transport, and Demand Planning. The task force met on a monthly basis through the end of the audit period (i.e., December 2007) and reviewed a number of topics and alternatives for improving SW Gas' daily gas forecasting system.

Among the improvements made to the model, as a result of the multi-step program conducted jointly with Marquette University, was the incorporation into the model nonlinear relationships between consumption and heating degree days at extreme temperatures.⁴²

- **Other Items:** The task force also investigated and implemented the usage of several other supporting analytical techniques to the GasDay model. These include the use of (1) scatter plots and (2) the development of 24-hour load curves for incremental heating degree days. The latter, which could help facilitate with mid-day corrections during the later scheduling cycles, required the receipt of hourly data from EPNG.

Curtailed Gas Supplies

By far the most significant factor behind the penalties assessed for SW Gas during the force majeure event was the curtailment of natural gas production in the San Juan basin. The latter occurred because of the rapid decline in temperatures in the basin which caused a large number of well freeze-offs. While total lost San Juan production on the EPNG system was about 0.5 BCFD, for SW Gas the difference between Cycle 4 scheduling and delivered San Juan supplies was approximately 83,000 Dth.⁴³ The latter is likely the best indicator of lost supply for SW Gas. Furthermore, even if SW Gas had scheduled a higher level of gas supply, it is doubtful that overall supplies would have increased appreciably, as the well freeze-off conditions were epidemic throughout the basin. Instead the amount of curtailed production for SW Gas likely would have increased under a scenario of an even higher level of scheduled supplies by SW Gas.

Under the EPNG system, SW Gas initiates the scheduling process by sending its detailed meter specific scheduling information to EPNG at the designated time (i.e., in this situation Cycle 1 schedules were submitted at 9:30 a.m. on the previous day; see Exhibit 2-9). However, the gas is not officially scheduled at that time, as then EPNG must initiate its confirmation process. Included in this confirmation process is the obtaining of information from the various suppliers as to how much gas supply they will provide at each meter. If the figures provided by SW Gas and the specified suppliers match for a specific meter, then the gas is scheduled. However, if there is a difference, then EPNG notifies SW Gas, which must then begin to initiate corrective action. This process is not instantaneous, as the contact and communication between the various

⁴² See "Excerpts from Demand Planning's Monthly Reports" and "Proposal for the Forecast Model Enhancements Project at Southwest Gas Corporation" prepared by Marquette University dated April 9, 2007.

⁴³ As noted in Exhibit 2-9 Cycle 4 scheduling was about 417,000 Dth. Actual gas delivered by SW Gas was about 333,900 Dth, with the difference being approximately 83,000 Dth, which equated to approximately 0.08 BCFD.

parties takes some time. As a result, until EPNG provides SW Gas with final confirmation of what gas supplies have been scheduled, SW Gas, like other EPNG customers, is in the dark as to actual scheduled quantities of gas and can only use its submitted schedule as an estimate.

During the November 30, 2006 event the flow of information was far from instantaneous, as a result there was both a lack of sound information on the status of scheduled gas supplies and uncertainty over conditions in general. This was particularly true for scheduled supplies from producers, as notification times by producers of their inability to supply contracted quantities of gas supplies varied with some producers declaring force majeure conditions much later than others. The rapid changes in the weather also caught the producers off guard, some of whom attempted to compensate for the loss in production from a given well with production from another well. However, eventually the problem became too great and the producers were forced to declare force majeure and some of these force majeure notifications did not materialize quickly.^{44,45}

By the time Cycle 4 scheduling had occurred, SW Gas had scheduled virtually all of its San Juan basin capacity from firm contracts and had turned to obtaining and scheduling spot supplies from the Permian basin, where well freeze-offs also had occurred. In hindsight it is almost ironic that after all the documentation on scheduled gas supplies finally was received that it was the firm contract supplies from the San Juan that were curtailed, while the spot gas supplies from the Permian were, for the most part, successfully delivered.⁴⁶

Observations

Both the severity of the weather and its rapid change appears to have caught most of the southwestern gas industry off guard, with well freeze-offs forcing producers to declare force majeure conditions, particularly in the San Juan basin. From the perspective of SW Gas, the gas supplies available to serve its customers were limited no matter how much gas it scheduled. SW Gas was limited in its ability to respond to these unusual and rapidly changing events because of the lack of timely receipt of information

⁴⁴ Based upon discussions with SW Gas management.

⁴⁵ Among the producing basins in the U.S. the San Juan basin is relatively unique, because of the large number of wells in the basin (i.e., there are about 35,000 wells in the basin of which about 27,000 are producing), which makes scheduling and confirmation of scheduled gas supplies even more difficult.

⁴⁶ See Larry Black memorandum dated January 30, 2007.

from EPNG and the suppliers. In addition, it appears that even if SW Gas had received this information on a more timely basis, it is doubtful SW Gas could have obtained a significant increase in gas supplies, as the entire region was under the equivalent of emergency conditions. Despite these mitigating factors, under the newly instituted EPNG tariff SW Gas was required to pay \$2.1MM in penalties, as a result of the events for November 30, 2006.⁴⁷

With respect to the penalties they could have been nearly double this amount if SW Gas and the other East of California customers earlier had not prevailed on eliminating the Daily Overrun Charges.⁴⁸ In addition, a subsequent Rate Case Settlement would reduce the amount of this penalty by 85 percent if these exact conditions were to repeat themselves in the future.⁴⁹

With respect to avoiding losing access to gas supplies under future force majeure conditions, independent of concerns about penalties, the only realistic alternative appears to gain access to market-area storage. Unfortunately, none exists within Arizona at the current time. Gaining access to production-area storage could help mitigate supply concerns, particularly on the second day of the event. At present the only production-area storage in the region is in the Permian basin. Unfortunately, the amount of such storage capacity is limited and the standard terms and conditions for such capacity are restrictive. Concerning the latter, both of the two key production-area storage facilities in the Permian basin require that any change in initial nominations for gas to be withdrawn from these storage facilities occur prior to the Cycle 1 scheduling time for EPNG. As a result, access to capacity from these facilities, if it had been available, would not have enabled SW Gas to get additional gas supplies on the first day of the event.⁵⁰ The issue of future access to storage capacity is discussed further in the recommendations section of this report.

⁴⁷ This assessment focuses on the first day of the four day event, namely November 30, 2006. Events for the second day, namely December 1, 2006 were similar and resulted in additional penalties of \$1.2MM. EPNG finally lifted the declaration of strained operating conditions (SOC) at 7:23 a.m. on December 4, 2006. The initial declaration of SOC occurred at 6:38 a.m. on November 30, 2006. Within this time frame critical operating conditions (COC) were declared from 11:22 a.m. on November 30, 2006 to 8:51 a.m. on December 3, 2006.

⁴⁸ Technically the elimination of the Daily Overrun Charges had been agreed to, but not yet implemented formally. However, EPNG waived the additional cost associated with the Daily Overrun Charges.

⁴⁹ February 6, 2008 conference call with SW Gas management.

⁵⁰ For the Enstor's Gamma Ridge storage facility changes to nominations must occur before 11 a.m. on the first business day preceding the day on which such change is to take place (i.e., on November 29 for gas delivered on November 30). For Chevron/Unocal's Keystone storage facility the requirement is before 9

Lastly, the events of November 30, 2006 to December 4, 2006 represent the first time SW Gas had to adapt to a force majeure event without a full requirements contract with EPNG.

Other Related Items

There are a few other items that merit discussion in this chapter even though they are either technically not part of the audit period or not directly part of the EPNG system.

Diversification

While for most LDCs it is desirable to connect to two or more interstate pipelines in order to diversify both access to supply and gas transportation capacity, in the case of SW Gas historically this has not been an alternative. However, in the future because of the proposed expansion of the Transwestern system, as a result of its Phoenix Lateral project, SW Gas will have the opportunity, albeit a limited one, to diversify its future transportation portfolio. Such diversification would help reduce SW Gas' dependence upon EPNG and its somewhat restrictive tariff.

The expected route for the Phoenix Lateral, which currently is scheduled to be completed in 2008, is primarily to the west and south of Phoenix and, as a result, it does not overlap significantly the EPNG system, which would be an ideal circumstance for SW Gas. Key factors in the selected route for the Phoenix lateral appear to be the immense difficulty in gaining right-of-way in the heavily populated areas to the west of Phoenix and a choice to divert the route around the White Tank Mountains. SW Gas has subscribed for capacity at the Sun Valley North, Sun Valley South, New Florence and Gilbert meter stations on the Phoenix Lateral project, as illustrated in Exhibit 2-10. The capacity at these locations primarily will be to serve future growth for SW Gas as each meter is close to master planned communities that are in the process of being developed. Currently there is no EPNG service to these areas.

a.m. on the day such change is to take place. Source: Excerpts from the operating statements for (1) Enstor's Gamma Ridge project and (2) Chevron/Unocal's Keystone project.

Exhibit 2-10. Southwest's Capacity Commitment To Transwestern's Phoenix Lateral

Tap Location	Capacity Commitment in Dth/day		
	Nov-Mar	Apr-Oct	Annual Average
Sun Valley-North	4,350	340	1,999
Sun Valley-South	8,390	660	3,858
Rainbow Valley	10,760	-	4,451
New Florence (Santan)	3,430	-	1,419
Germann (Santan)	47,090	-	19,481
Gilbert (Santan)	980	-	405
Total	75,000	1,000	31,613

Source: Mr. William Moody memorandum to the Arizona Corporation Commission dated February 22, 2006.

In addition, SW Gas has subscribed to capacity on the Phoenix Lateral at the Rainbow and German meters, where currently EPNG also has meters. As a result, service at these two points⁵¹ will be in direct competition to existing EPNG service and if the most economic alternative could allow SW Gas to displace service previously provided by EPNG and potentially avoid exposure to penalties at these two points. Unfortunately, these are the only two points with such potential overlaps and thus competition exists. Lastly, there has been some discussion of moving the Sun Valley North meter to the north and east, if the Phoenix Lateral can be rerouted. If this were to occur, SW Gas would be able to displace current EPNG services at this revised location.

Storage

Independent of the fact that the force majeure events of November 30, 2006 through December 4, 2006 resulted in penalties being assessed against SW Gas, which is an undesirable event, probably the more significant issue is the potential threat to providing adequate service when a similar force majeure event occurs in the future. Under such conditions SW Gas may not be able to have access to adequate gas supplies to meet customer demand.^{52,53} The decline in the EPNG linepack during the November 30

⁵¹ These two meter points account for about 75 percent of SW Gas' capacity on the Phoenix Lateral.

⁵² This issue of well freeze-offs under unusual weather conditions and the subsequent curtailment of production is not unique to Arizona. While hopefully such events will be rare, they can happen and storage is the key tool to compensate for such an event. For the U.S. as a whole the classic examples are: (1) the winter of 1976/1977 and (2) the winter of 1989/1990, when ice flows occurred 12 miles out into the Gulf of Mexico (i.e., see EPRI, *U.S. Natural Gas Industry: Impact of the Winter of 1989/1990* (OCSP-7102), January 1991).

⁵³ Force majeure events have happened in the past in the San Juan basin and very likely will happen again, although predicting the timing of such future events is nearly impossible. Factors that make the San Juan

event was alarming (i.e., see Exhibit 2-7) and SW Gas because of its 'obligation to serve' and its inability to fuel switch⁵⁴ is probably the most sensitive East of California customer to such a phenomenon. While there are few things SW Gas might do to mitigate the impact of a future force majeure event, the primary vehicle for protecting against such circumstances and ensuring SW Gas meets its 'obligation to serve' is to gain access to market-area storage. While currently no market-area storage exists in Arizona, it is possible that some market-area storage could be developed in the future. Since the development of market-area storage likely will be done by third-party developers because the financial costs may be beyond SW Gas' capabilities, it is suggested that the Arizona Corporation Commission (ACC) may want to consider the following items:

- **Project Promotion:** The ACC may want to consider adopting even more proactive policies for the development of market-area storage in Arizona than the policies on this subject have been previously set forth.⁵⁵ While it is realized that there are pros and cons to developing such policies, a more proactive position by ACC is suggested. This could include:
 - (1) definite pre-approval for the cost-recovery associated with subscribing to capacity for such projects,
 - (2) a stipulation the likely increase in costs associated with having access to market-area is in the best long-term interest of customers (i.e., similar to an insurance policy to ensure that the 'obligation to serve' is met under adverse circumstances)⁵⁶ and
 - (3) potentially providing incentives for the development of market-area storage.⁵⁷ In making these suggestions it is realized that any potential market-area storage projects must meet two key thresholds, namely that the storage project is technically sound and that it is financially viable. Also, it is realized that meeting these two threshold requirements will be a challenge and that off-the-wall projects that might be proposed by various promoters are not acceptable.

basin vulnerable to well freeze-offs are (1) the very large number of wells in the basin (i.e., about 35,000 in total), (2) the fact that many of these wells are condensate rich and (3) it can get very cold in the basin (e.g., 5°F).

⁵⁴ Many electric utilities can either directly or indirectly switch to alternative fuels to run their plants, when gas supplies are curtailed. Direct fuel switching involves the use of distillate to fuel the plant, even if just for a single day, while indirect fuel switching involves the use of purchased power on the grid to replace lost gas-fired generation.

⁵⁵ See "ACC Policy Statement Regarding New Natural Gas Pipeline and Storage Costs" dated December 18, 2003.

⁵⁶ The ACC could work with East of California customers to establish tolerable bands of cost increases for such 'insurance policy' projects.

⁵⁷ The incentives could be recoupable depending upon the success of the project.

- **Copper Eagle:** While, in general, the ACC cannot be biased towards any specific market-area storage project, the Copper Eagle site may be an exception because of the very limited alternatives in Arizona.⁵⁸ The suggestion is that the ACC may want to consider either directly or indirectly obtaining an option on the Copper Eagle site and thoroughly investigating the historical challenges to this project. Such a thorough and unbiased investigation could establish that the Copper Eagle site is a viable storage site that has characteristics that are similar to many, if not most, of the existing storage facilities in the U.S.

While no one likes to dwell on worst case scenarios, the potential consequences of the combination of inadequate supplies due to a major well freeze-off event and the lack of access to market-area storage can be significant for the region. In the worst case sections of the SW Gas system likely would lose pressure, which could cause pilot lights to go out. Relighting a large number of residential and small commercial pilot lights is a significant undertaking, which could require action by both SW Gas and state institutions. Similarly, brown outs for electric power could emerge as a result of some gas-fired electric units not being able to either fuel switch or obtain adequate purchased power. The region's sensitivity to the latter has increased significantly as a result of the large amount of gas-fired generation that has been built in Arizona in the recent past.⁵⁹

With respect to items that could be done in the interim until market-area storage becomes available, the following should be considered:

- **New ACC Policy:** Because the natural gas load for electric utilities in Arizona is large and many of these electric utilities have the ability to fuel switch, particularly during periods of constrained gas supplies, it is suggested that the ACC actively pursue developing both a policy and a coordinating committee of industry representatives that would promote the swapping of gas supplies during future periods of curtailed gas supplies. Such a policy would go a long way to ensure that residential gas demands are met under such conditions and that the 'obligation to serve' is met. There will be cost issues involved in such a policy – for example, if an LDC receives gas supplies scheduled by an electric utility under such a crisis mode, the LDC would have to compensate the electric utility at its cost for an alternative fuel (i.e., distillate and/or purchased power). In addition, the committee would have to be a 'standing committee' that is capable of assessing viable alternatives and enacting them quickly once the crisis conditions emerge. Other regions have had success with such efforts. For example, historically the state of Texas has had such a 'standing committee' to respond to well freeze-offs and this committee has had some success in dealing with such events. Similarly, in the New England region efforts to establish and

⁵⁸ In general, the geology of Arizona significantly limits the potential sites for developing storage.

⁵⁹ During the winter of 1989/1990 interstate pipelines were forced to curtail firm transportation and there were rolling blackouts among some electric utilities. See EPRI, *U.S. Natural Gas Industry: Impact of the Winter of 1989/1990* (OSCP-7102), January 1991.

encourage coordination between LDCs and electric utilities has had some success.⁶⁰

- **Diversify Supplies:** It is recommended that SW Gas carefully track the likelihood of LNG imports entering the Southwest gas market⁶¹ and consider gaining access to such supplies, in an effort to diversify its gas supplies and reduce its dependence on San Juan basin gas supplies. Any such effort should be evaluated carefully as there are cost issues involved with obtaining such supplies, as well as infrastructure issues. Concerning the latter, these LNG imports likely will be transported via the Baja pipeline to Erhenberg, which over time likely will make Erhenberg a liquid point for these gas supplies. However, SW Gas will still have to work with EPNG to obtain back haul capacity and a reasonable rate for such capacity.

Refunds

While the subject of refunds is discussed more fully elsewhere in this report, it is noted briefly noted here for completeness. As illustrated in Exhibit 2-1, during the audit period SW Gas did incur \$3.3MM in additional charges and penalties. However, SW Gas also received \$11.2MM in refunds during 2007 (i.e., see Exhibit 2-11) of which approximately \$1.9MM represents refunds of additional charges and penalties.⁶² As previously noted, obtaining these refunds for the various additional charges and penalties required a considerable proactive effort by SW Gas.

Transportation Customers

During the audit period, SW Gas provided service to between 80 and 100 transportation only customers (i.e., SW Gas' T-1 tariff). These transportation customers, which receive supply at about 200 SW Gas meters and are primarily industrial firms, are supposed to arrange for their own gas supplies and interstate gas transportation capacity to the appropriate SW Gas city gate or tap and then pay SW Gas a fee for transporting the gas on its system. This concept emerged during a period in the industry when it was thought that this option for industrial customers would promote flexibility in obtaining gas supplies and thus, aid in reducing the overall costs of end user gas supplies. While the merits of this concept may have been sound during the 'full requirements' era for the EPNG

⁶⁰ See EPRI, *Natural Gas and Electric Industry Coordination in New England* (TR-102948), November 1993.

⁶¹ The Energia Costa Azul regasification project (i.e., one BCFD) is under construction and scheduled to come online about March 2008. In addition, the projects developers have contracted for LNG supplies with Indonesia's Tangguh facility (i.e., online 2008 and 2009) and Russia's Sakhalin Island project (i.e., online in 2008 and 2009). Supplies for the latter likely will be replaced by LNG supplies from Australia's Gorgon facility once it comes online (i.e., estimated to be 2012 or 2013). Only a portion of these LNG supplies will be transported to the U.S., as some LNG supply will be consumed within Mexico.

⁶² The \$1.9MM figure includes an estimated allocation of interest of \$132,000.

Exhibit 2-11. EPNG Refunds To SW Gas For Arizona Operations⁽¹⁾

Category	2006 EPNG Settlement Refund (\$000)	2007 EPNG Settlement Refund (\$000)	Total (\$000)
Reservation Charges	\$4,687	\$4,016	\$8,703
Daily Volume Penalty	\$237	\$967	\$1,204
IHSW Charges	\$83	\$138	\$221
Unauthorized Daily Overrun Penalty	\$69	\$79	\$148
Unauthorized Hourly Overrun Penalty	\$1	\$111	\$112
Usage Charges	\$66	\$36	\$102
Scheduling Penalty	\$2	\$40	\$42
MDO/MHO Penalty	\$44	(\$37)	\$7
Credits ⁽²⁾	(\$33)	(\$91)	(\$124)
Interest	\$532	\$259	\$791
Total	\$5,689 ⁽³⁾	\$5,519 ⁽³⁾	\$11,208 ⁽³⁾

(1) Also, there were \$1.2MM in refunds associated with SW Gas' Nevada and California operations.

(2) Credits include demand charge and capacity release credits.

(3) Figures may not add due to rounding.

pipeline, they create a number of problems under the new EPNG tariff. Among these problems is that variances in even hourly gas loads for these transportation only customers can result in additional penalties for SW Gas. While the additional charges and penalties attributable to these transportation only customers should be allocated back to them,⁶³ such a tracking system takes considerable effort. While the basic components of this concept already have been addressed by SW Gas,⁶⁴ it appears that overall this concept may not have been SW Gas' highest priority in light of all the other items to which SW Gas management had to adapt as a result of the new EPNG tariff.

While no LDC likes to irritate its customers, going forward it is recommended that SW Gas become much firmer with these transportation only customers and require detailed documentation of both gas supply contracts and interstate capacity contracts, even if merely interruptible capacity contracts. In addition, SW Gas should increase its capability to monitor hourly gas flows for these customers⁶⁵ and allocate EPNG penalties

⁶³ One example emerges from the \$2.1MM of penalties incurred by SW Gas on November 30, 2006 as a result of the force majeure event. Approximately \$121,000, or six percent, of these penalties were the result of actions by transportation only customers. See Larry Black memorandum dated January 30, 2007.

⁶⁴ See ACC Docket No. G-01551A-06-0746 Decision No. 69668.

⁶⁵ There likely will be cost-benefit tradeoffs for some of these customers, as the cost to monitor their gas flows may exceed the benefit of tracking them. This is a judgment call that should be left up to SW Gas management.

resulting from any variance in gas flows caused by these customers. This type of compliance enforcement likely will be an irritant to some transportation only customers,⁶⁶ but under the new EPNG tariff it has become a necessity – otherwise the remaining SW Gas customers will be unfairly charged for the actions of others.

While SW Gas has accomplished some of the above items for some transportation only customers, in the future it needs to push forward for 100 percent compliance of the above items. It is realized this more aggressive compliance approach likely will cause some transportation only customers to return to being regular SW Gas customers, as there is considerable effort required on their part to be fully responsible for all aspects of gas supply, except for the final transportation element on a LDC.

⁶⁶ In hindsight some of these transportation only customers may have, in essence, received a free ride with respect to obtaining their own gas supplies, because of the lack of enforcement by SW Gas. The transition for these types of transportation only customers may be very difficult and potentially costly.

3

GAS PROCUREMENT

Overview

This section of the report examines:

- (1) Southwest Gas' gas procurement strategies and conclusions about their effectiveness,
- (2) the resulting gas prices and their prudence,
- (3) Southwest's internal procurement policies and procedures along with a number of management recommendations for improvement,
- (4) an audit of the quantities and volumes of the Monthly Bank Balance Statements versus the GTS¹ amounts, and
- (5) an audit of selected transactions vis-à-vis Southwest Gas' policies and procedures along with a number of management recommendations.

One of EVA's core analysis methodologies was based on a bottom-up evaluation of the transaction data of the GTS system. GTS breaks out each and every unique supplier contract at the daily level of the audit period (totaling more than 19,300 line items) for volumes scheduled by Southwest's gas buyers. Many of the exhibits include the subtitle, "Based on Audit of Transaction Data", and subsequently this refers to EVA's analyses of the GTS database.

¹ Gas Transaction System is Southwest Gas' internal deal capture system.

In addition, Southwest's internal documents were reviewed. Onsite meetings occurred over three days in mid-January 2008 including monitoring of the next-day gas acquisition, nominating and scheduling processes on El Paso Pipeline, as well as various follow-up teleconference calls and further data requests. The selection of specific transactions that were audited is discussed in that final section. EVA conclusions and recommendations are summarized in the Executive Summary.

Gas Supply Strategy

EVA believes that Southwest Gas' gas supply strategies were prudent and reasonable during the audit period covering September 2004 through April 2007. The key elements of Southwest Gas' portfolio supply strategy have essentially remained the same since the testimony of William Gehlen to the Arizona Corporation Commission (ACC) on July 26, 2005 covering the period September 2003 through August 2004, and as described in a report by Ralph E. Miller submitted by Southwest Gas to the ACC in July 2006. The three key elements of Southwest Gas' supply strategy can be summarized as:

- **Arizona Price Stability Purchases (APSP):** The APSP is baseload fixed priced gas purchased in the months proceeding the November through March high demand season. Southwest Gas attempts to meet 100% of expected minimum load for next winter with this type of gas and about 50% of total annual supply. The objectives of the APSP are to pay more for firmness of supply and stability of price. The audit found that APSP gas was purchased from 3 to 23 months forward² of the physical flow month. The majority of gas is purchased from two San Juan Basin receipt points – Bondad Station and Blanco – since San Juan in theory tends to be lower priced than Permian.
- **Index, or Term, Purchases:** This element of the gas supply portfolio stands ready to meet variable and unpredictable load. It is also mostly firm supply with swing volumes and prices that float on published indices to be used for peaking demand. Supply is diversified by adding delivery receipt points at Permian Keystone and finally at Waha (being the most expensive traditionally). Southwest Gas models warm, normal, and cold temperature scenarios for the load forecast and includes scenarios that prepare for the all-time peaks.
- **Spot and Interruptible Purchases:** This element includes spot purchases for the next day or short time windows and includes interruptible gas that is relied heavily upon during the summer months. The summer months are the lowest demand season for Southwest's customers and there is high probability that the interruptible gas will not be cut during the summer. Also if interrupted during the summer, replacement supply is typically easily available from the marketplace.

² More discussion of this practice follows in the Policies and Procedures section

Exhibit 3-1 summarizes Southwest's use of the three supply elements during the entire audit period. Southwest did follow gas supply strategies that were similar to both its intended strategies and to past strategies, as stated in various Southwest documents submitted to the Commission. The total scheduled volumes of 173,696,102 mmBtu were based about 58% on fixed price supply, about 20% on floating index price supply, and 22.5% on spot/interruptible purchases over the entire audit period. The resulting value of \$1,132,941,000 was about 58% on fixed price supply, about 21% on floating index price supply, and more than 21% on spot supply. Southwest gas supplied and diversified its gas portfolio from the potentially least expensive gas receipt points with 88% of the volume from the San Juan Basin, 8% of supply from the Permian Basin, and 4% from Waha.

**Exhibit 3-1. Summary Of Gas Supply Portfolio, September 2004-April 2007
(Based on Audit of Transaction Data)**

Portfolio Element	Fixed	Index	Spot	Total
Volume (mmBtu)	100,117,753	34,420,378	39,157,971	173,696,102
	57.6%	19.8%	22.5%	100.0%
Value ('000)	\$ 652,443	\$ 234,581	\$ 245,917	\$ 1,132,941
	57.6%	20.7%	21.7%	100.0%
Receipt Point	San Juan	Permian	Waha	Total
Volume (mmBtu)	152,644,841	14,040,650	7,010,611	173,696,102
	87.9%	8.1%	4.0%	100.0%
Value ('000)	\$ 983,531	\$ 91,504	\$ 57,906	\$ 1,132,941
	86.8%	8.1%	5.1%	100.0%

Southwest's heavy reliance on the APSP as the largest component of its portfolio supply strategy appears prudent to compensate for its lack of access to storage capacity, a critical tool that most LDCs use to manage volatility and meet seasonal demand. Market-area storage is the key infrastructure component that achieves balancing between sudden load and pipeline flow changes, and other exogenous events such as pipeline problems or supply force majeure. While there is a wide range of practices among utilities, one study showed that U.S. LDCs purchase forward baseload supply to meet some 60-80% of their current year load requirements and also use forward supply to meet between 15-30% of their next year's requirement.³ SWG's policies prohibiting

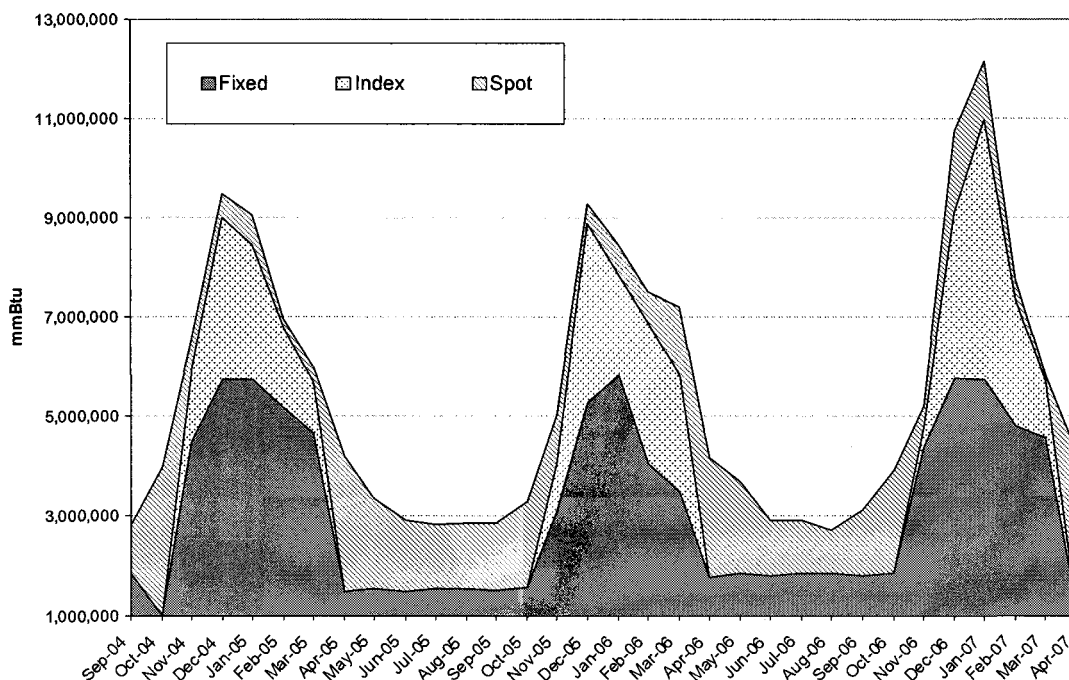
³ National Rural Electric Cooperative Association, 2002. *Strategic Fuel Supply Guide*, Project 01-39.

the outright sale of excess gas to third parties also prevents any greater reliance on the fixed price baseload element.

Southwest's use of the other two supply elements is an attempt to diversify its supply portfolio sufficiently with inverse characteristics than the firm baseload characteristics. The term or index purchases are essentially options that give SWG the right but not the obligation to call on firm gas supply for a very small premium over index of up to several cents per mmBtu. Likewise the use of spot gas and interruptible gas helps Southwest diversify its supply portfolio with elements that can be tapped when the economics are attractive. These three elements appear to have served SW Gas well to meet its commitment to serve its regulatory load.

Exhibit 3-2 shows the results of SW Gas' supply strategy during the audit period as actual purchases by supply element varied seasonally and monthly. APSP fixed price supply varied from 47 to 84% of the total during the winter months of November through March, and fell to 28 to 67% of the total portfolio during the shoulder and summer

**Exhibit 3-2. Composition Of Gas Supply Portfolio
(Based on Audit of Transaction Data)**



months of April through October. Index gas was purchased only during November through March satisfying 8 to 43% of monthly winter needs. The spot element, that includes interruptible purchases, was relied upon in all months of the year and ranged from 2% to 20% of the total during November through March, versus 32 to 75% of the total during April through October.

Analysis between calendar years, or SW Gas' conventional gas years from November through October, is somewhat limited because the audit period contains only two complete calendar years or SW Gas years (November-October), three complete winters, and two complete summers. Therefore EVA comparisons are limited to between the seasons and between the months throughout the audit period.

Exhibit 3-3 compares the three winters of the audit period. Load increased substantially during the 2006/07 winter to its highest level of the audit period, suggesting cool temperatures, and conversely warm temperatures in 2005/06. Simple averages across the five winter months show inherent variability between years due to weather and also reflect management decisions during the planning periods.

**Exhibit 3-3. Composition Of Supply Portfolio During Winter Seasons
(Based on Audit of Transaction Data)**

Winter	Nov-Mar Volume (mmBtu)	Simple Average of Winter Months		
		Fixed	Index	Spot
2004/05	38,005,857	69%	25%	6%
2005/06	37,446,825	58%	30%	12%
2006/07	41,606,209	65%	27%	8%

Variations occur in the composition of the supply portfolio at the monthly level. During the core summer months, the contribution of spot and interruptible gas holds fairly steady, in the absence of winter heating load. The contribution of baseload gas to the core summer months, June-August, is also fairly steady. Sharper differences emerge between the winter months that are driven largely by the divergences of actual heating degree days from normal heating degree days. As an example, in November 2006 the contribution of fixed price baseload gas was unusually high at 84% of total requirements

but contributed only 47% of total requirements in January 2007. Exhibit 3-4 shows heating degree days for Phoenix for the first three months of the 2006/2007 winter. The heating degree day data shows that November 2006 was fairly warm at only 37% of normal heating degree days, whereas January 2007 was 13% colder than normal for Phoenix.⁴

Exhibit 3-4. Heating Degree Days For Phoenix, AZ

	Normal	Actual	% of Norm
Nov-06	129	48	37%
Dec-06	318	322	101%
Jan-07	322	363	113%

Source: NOAA/NWS

Exhibit 3-5 shows the detail of the supply portfolio at the monthly level. Such variation between winter months also testifies to the difficulty of matching baseload supply to a load forecast produced some four to six months earlier, and in absence of a full requirements contract. The largest load swing variation between the 32 months of the audit period is measured between August 2006 and January 2007 from 4,151,768 to 12,139,138 mmBtu, a swing of 9,423,624 mmBtu or almost 4.5 times. This difference from low to high also represents 15% of annual 2006 consumption of 62,438,087 mmBtu.

Day-to-day variability can also be severe. Late November and early December 2006 are of particular interest due to the supplier force majeure events resulting from the gas production well freeze-offs, as discussed in Chapter 2. On November 30, 2006, SW Gas load spiked upward by some 238,440 mmBtu to 488,395 mmBtu⁵ when compared to the prior day's scheduled volume (including the load forecasting shortfall/error of some 108,000 mmBtu). Transactional data in GTS, and summarized in Exhibit 3-6, show that for November 30, total scheduled gas to Southwest increased by 56,458 mmBtu versus the prior day, based on scheduled baseload supply falling 19,696 mmBtu, scheduled swing gas rising 61,927 mmBtu, and scheduled spot gas rising 14,227 mmBtu (for Cycles 1 through 4). These numbers above suggest that higher pipeline receipts only

⁴ Phoenix was chosen as an example since it represents about 80% of Southwest's jurisdictional load in Arizona.

⁵ January 30, 2007 memo of Larry Black estimates November 30 load at 488,395 mmBtu and is compared to GTS scheduled volume of 249,955 mmBtu, hence EVA's phraseology for the daily load swing of "some".

Exhibit 3-5. Monthly Detail Of Supply Portfolio
(Based on Audit of Transaction Data)

Date	Total Value		Total Volume		Composition of Volume		
		(\$1000s)		(mmBtu)	Fixed	Index	Spot
Sep-04	\$	11,878		2,794,397	66.2%	0.0%	33.8%
Oct-04	\$	19,225		3,966,930	24.8%	0.0%	75.2%
Nov-04	\$	35,964		6,512,148	68.9%	21.4%	9.7%
Dec-04	\$	53,890		9,466,109	60.6%	34.5%	4.9%
Jan-05	\$	49,209		9,058,663	63.3%	30.1%	6.6%
Feb-05	\$	37,792		6,972,344	74.1%	23.4%	2.5%
Mar-05	\$	32,773		5,996,593	77.5%	17.2%	5.3%
Apr-05	\$	24,989		4,181,213	35.6%	0.0%	64.4%
May-05	\$	19,064		3,340,168	46.2%	0.0%	53.8%
Jun-05	\$	16,054		2,896,834	51.3%	0.0%	48.7%
Jul-05	\$	15,918		2,808,974	54.9%	0.0%	45.1%
Aug-05	\$	18,306		2,860,500	54.1%	0.0%	45.9%
Sep-05	\$	19,424		2,856,089	52.5%	0.0%	47.5%
Oct-05	\$	25,278		3,289,504	47.1%	0.0%	52.9%
Nov-05	\$	38,925		5,020,676	61.2%	19.3%	19.6%
Dec-05	\$	76,480		9,273,958	57.0%	38.7%	4.4%
Jan-06	\$	58,632		8,456,092	68.7%	24.0%	7.4%
Feb-06	\$	48,497		7,494,424	54.2%	37.4%	8.4%
Mar-06	\$	44,373		7,201,675	48.4%	32.3%	19.4%
Apr-06	\$	24,909		4,151,768	42.6%	0.0%	57.4%
May-06	\$	21,897		3,666,643	50.4%	0.0%	49.6%
Jun-06	\$	17,021		2,899,208	62.1%	0.0%	37.9%
Jul-06	\$	17,410		2,909,847	63.2%	0.0%	36.8%
Aug-06	\$	17,387		2,715,514	67.8%	0.0%	32.2%
Sep-06	\$	18,460		3,109,089	57.9%	0.0%	42.1%
Oct-06	\$	21,034		3,919,284	47.5%	0.0%	52.5%
Nov-06	\$	42,193		5,186,157	84.3%	7.7%	8.0%
Dec-06	\$	80,570		10,728,386	53.7%	31.2%	15.0%
Jan-07	\$	88,176		12,139,138	47.1%	43.1%	9.8%
Feb-07	\$	61,292		7,745,092	62.0%	32.7%	5.3%
Mar-07	\$	46,427		5,807,436	78.4%	19.8%	1.9%
Apr-07	\$	29,493		4,271,249	27.9%	0.0%	72.1%

met 24% of Southwest's day-to-day load spike⁶ despite nominations that totaled some 417,000 mmBtu during Cycles 1-4 for November 30⁷. One fortunate factor for SW Gas is that this event occurred on the last day of November, with higher amounts of baseload gas scheduled to kick-in on day two of the event since the new gas month of December had significantly higher volumes of planned baseload gas. El Paso allows its shippers to

⁶ Versus the prior day, this November 30th calculation assumes increased scheduled volume of 56,458 mmBtu against increased load of 238,440 mmBtu.

⁷ Internal memo of Larry Black from January 30, 2007. This memo also states that Southwest increased its total nominated volumes for Cycle 3 by 50,000 mmBtu and by for Cycle 4 by 70,000 mmBtu. GTS only shows scheduled, not nominated or actual received volumes.

make-up the previous month's shortfall during the first ten days of the next month, and Southwest attempted to minimize November's shortfall as seen by the higher scheduled volumes through December 4.

**Exhibit 3-6. Scheduled Gas Supply During The 2006 Force Majeure Event
(Based on Audit of Transaction Data, mmBtu)**

Flow Date	Volume	Fixed	Index	Spot
11/28/2006	204,564	146,880	10,000	47,684
11/29/2006	249,955	146,570	30,000	73,385
11/30/2006	306,413	126,874	91,927	87,612
12/1/2006	291,744	175,855	38,635	77,254
12/2/2006	365,992	181,350	39,220	145,422
12/3/2006	379,306	181,734	39,741	157,831
12/4/2006	421,932	183,325	19,501	219,106

Gas Pricing

SW Gas' procurement strategies were effective at providing price stability - one of the two main objectives of the Arizona Price Stabilization Plan. EVA also concluded, based on the analysis of all of SW Gas' natural gas supply transactions during the audit period September 2004 through April 2007, that transactions executed and prices paid were reasonable and prudent. Exhibit 3-7 shows that SW Gas' procurement strategies produced a mean average cost of gas that was similar to the market price of gas, when measured against the entire audit period.

**Exhibit 3-7. Summary Of Prices, September 2004-April 2007
(Based on Audit of Transaction Data)
\$/mmBtu**

	Mean	Std. Dev.	Max	Min
Southwest Gas Portfolio	6.35	1.02	8.25	4.25
San Juan - Daily Index	6.38	1.47	10.90	4.26
Permian - Daily Index	6.59	1.55	11.03	4.35
Waha - Daily Index	6.65	1.49	10.92	4.53
San Juan - FOM Index	6.26	1.49	10.82	3.43
Permian - FOM Index	6.44	1.47	10.75	3.57

Source: Platts Inside FERC's Gas Market Report for daily and first of month indexes.

The similarity of Southwest's price to market price, within pennies when measured over the entire period, is a result of their supply strategies discussed above. Also, SW Gas' diversity to a large number of suppliers also helps ensure access to competitive prices. The APSP element provided price protection to SW Gas customers during the strong natural gas rally of 2004 and 2005, while the index and spot/interruptible elements were priced closer to prevailing market values as seen in Exhibit 3-8. In addition to meeting highly variable loads, the index and spot gas also benefited consumers as gas market prices dropped. Because their contract values are based on floating monthly or daily price indices, or bilateral daily transactions, their prices are naturally close to market, and hence allowed Southwest customers to participate as the market price declined in 2006 and 2007. Exhibit 3-8 also shows that Southwest's full portfolio price during any one month will typically lie between the lagging fixed element and the floating prices of the index and spot elements. As expected, the fixed price element of the portfolio was very low in the first half of the audit period as market prices climbed, and then continued to climb in the second half of the audit period keeping the fixed price element high until all of the \$8 to \$11/mmBtu gas was able to roll off, up to some 23 months after index prices peaked.

**Exhibit 3-8. Average Weighted Monthly Prices By Portfolio Element
(Based on Audit of Transaction Data)**

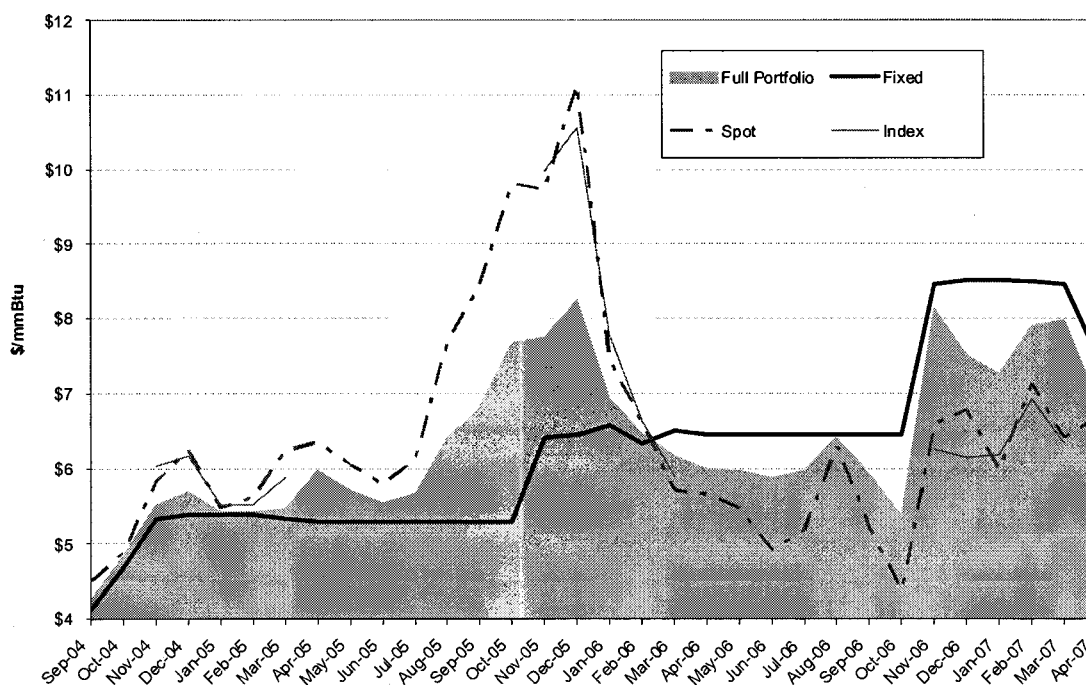
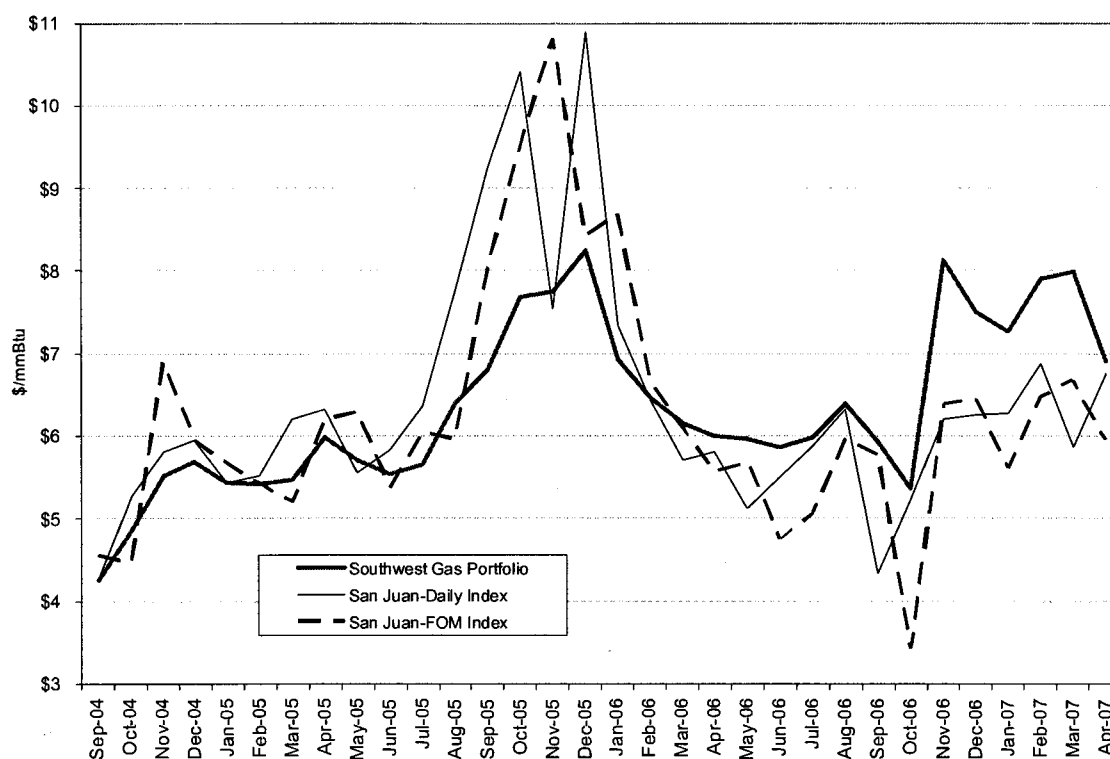


Exhibit 3-9 compares the average monthly values of Southwest's full portfolio to the published San Juan indices for first of month settlement (resulting from bid week) and to daily settlement during the audit period. For this illustration, San Juan was selected since it represented 88% of the total gas volume during the audit period. As expected and consistent with the above discussion about supply strategy, Southwest's weighted price was below or near market indices during the first half of the audit period. (Note: The other 12% typically based on Permian and Waha receipt points would have a tendency to pull up the SW Gas price versus the San Juan price.) Also as expected, Southwest's weighted price was higher than the San Juan price indices during the second half of the audit period.

**Exhibit 3-9. Price Comparison
(Based on Audit of Transaction Data)**



SW Gas' procurement strategies were also effective at reducing price volatility — the second main objective of the Arizona Price Stabilization Plan. Exhibit 3-7 referenced formerly, shows that SW Gas achieved a significantly smaller standard deviation around

the mean average price when compared to market indices during the audit period. One standard deviation measures \$1.02/mmBtu for the Southwest portfolio, compared to \$1.47-\$1.55/mmBtu for the published market indices. This is a significant reduction in volatility of 30-31%, as measured by standard deviation. Exhibit 3-10 shows the seasonal price deviations compared to the mean average price of the audit period. As expected, winters tend to be above the mean average price of the portfolio, while summers and shoulder months tend to fall below the mean average price of the portfolio.

**Exhibit 3-10. Monthly Price Change From Mean Average Price
(Based on Audit of Transaction Data)**

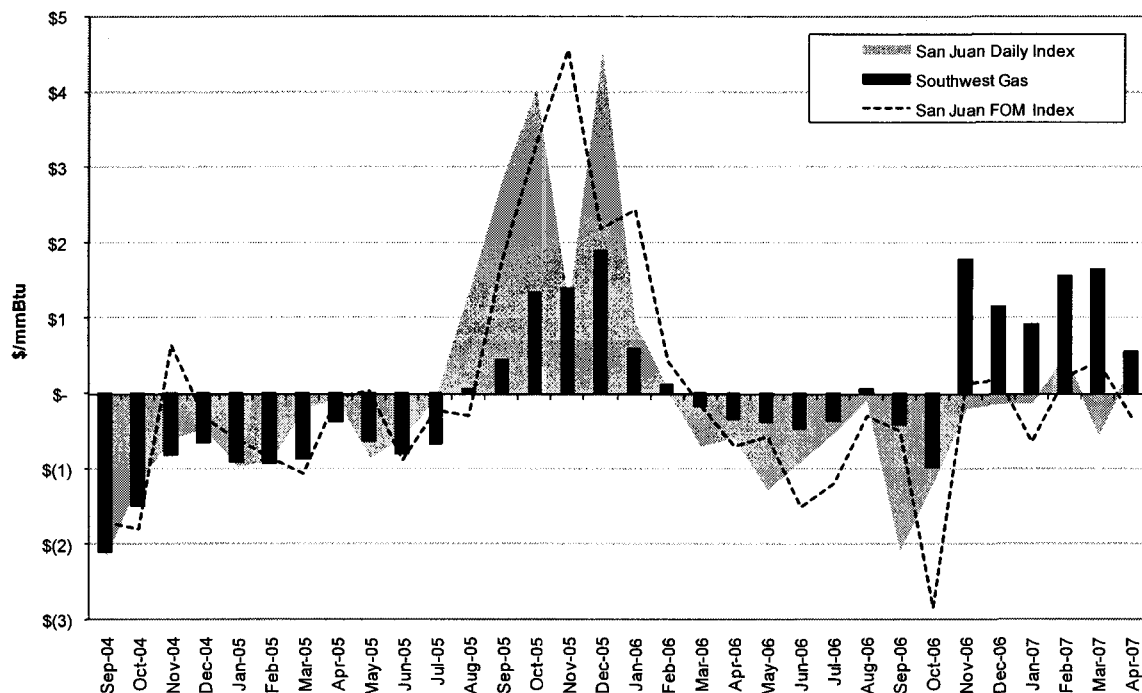
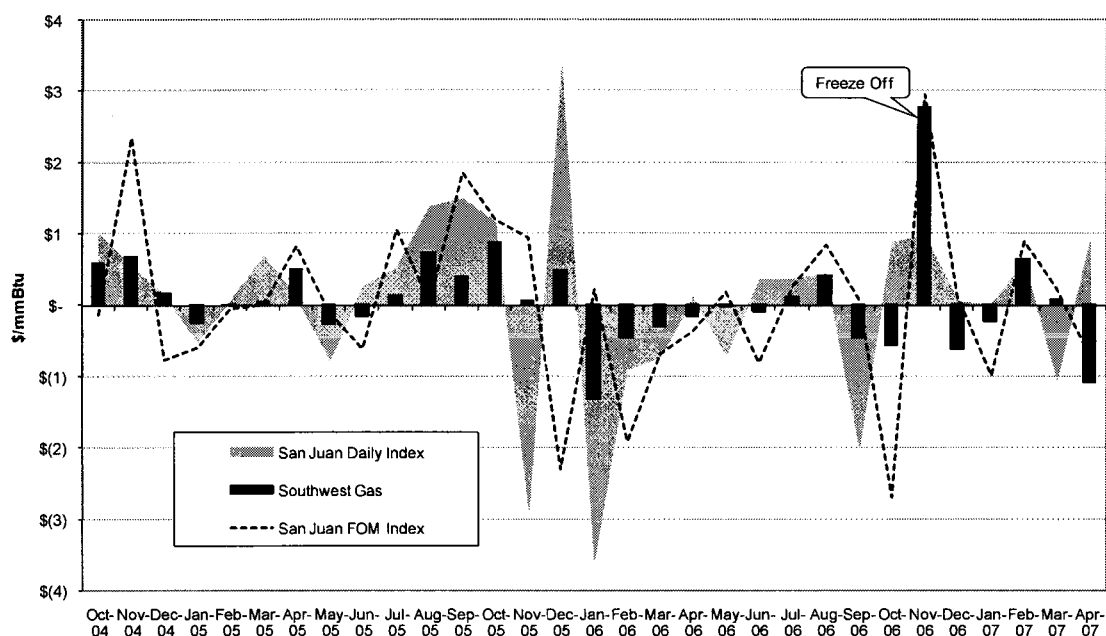


Exhibit 3-11 also shows the monthly change in price compared to the prior month. In almost all cases, Southwest's results shows lower price volatility compared to the market price indices.

The price indices used by SW Gas in setting their natural gas purchase prices are standard industry indexes with good market liquidity. The published price indexes used in SW Gas transactions are believed to be limited to:

- Gas Daily, El Paso San Juan Basin
- Gas Daily, El Paso Permian
- Gas Daily, El Paso Bonadad
- Gas Daily, Waha
- Inside FERC, First of Month, El Paso San Juan Basin
- Inside FERC, First of Month, El Paso Permian

**Exhibit 3-11. Monthly Price Change From Prior Month
(Based on Audit of Transaction Data)**



Exhibits 3-12 and 3-13 illustrate the number of discrete transactions and the related underlying volume of gas tracked during bid week and used by *Platt's Inside FERC Gas Market Report* to set its First of Month published price indices for the San Juan Basin and Permian Basin. A substantial analysis of market liquidity might be required if SW Gas was going to accept an index price for all, or a larger percentage, of its gas supply portfolio.

Exhibit 3-12. Volume Of Bid Week Gas Included In Published FOM Indices

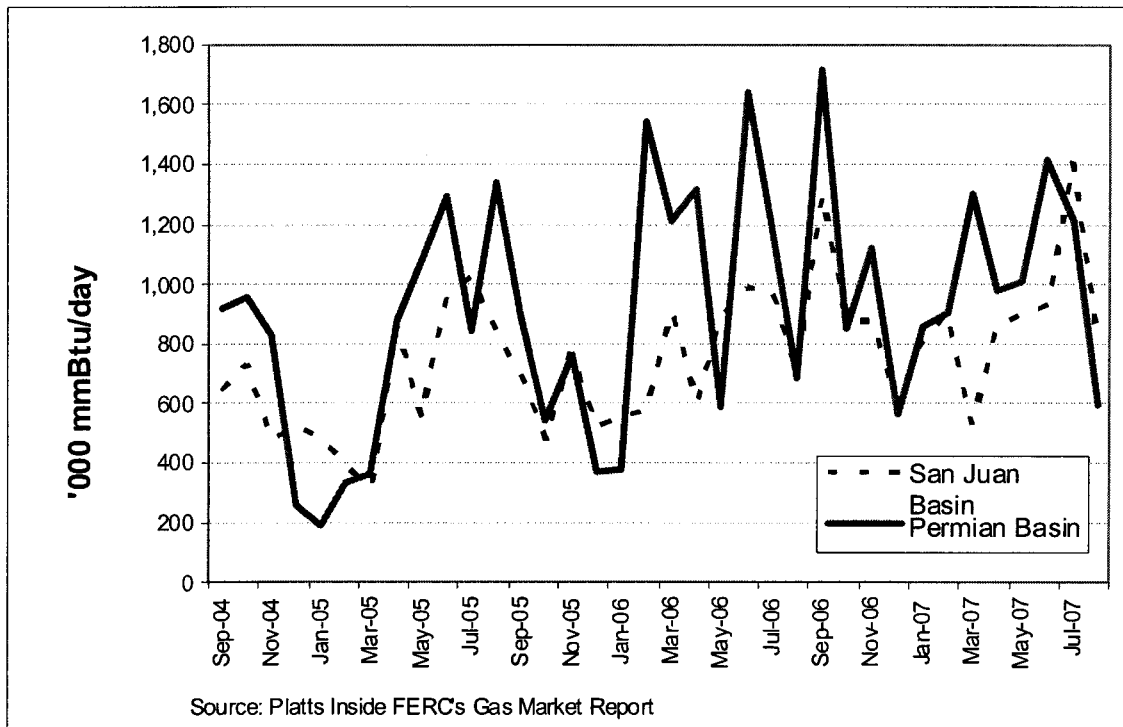
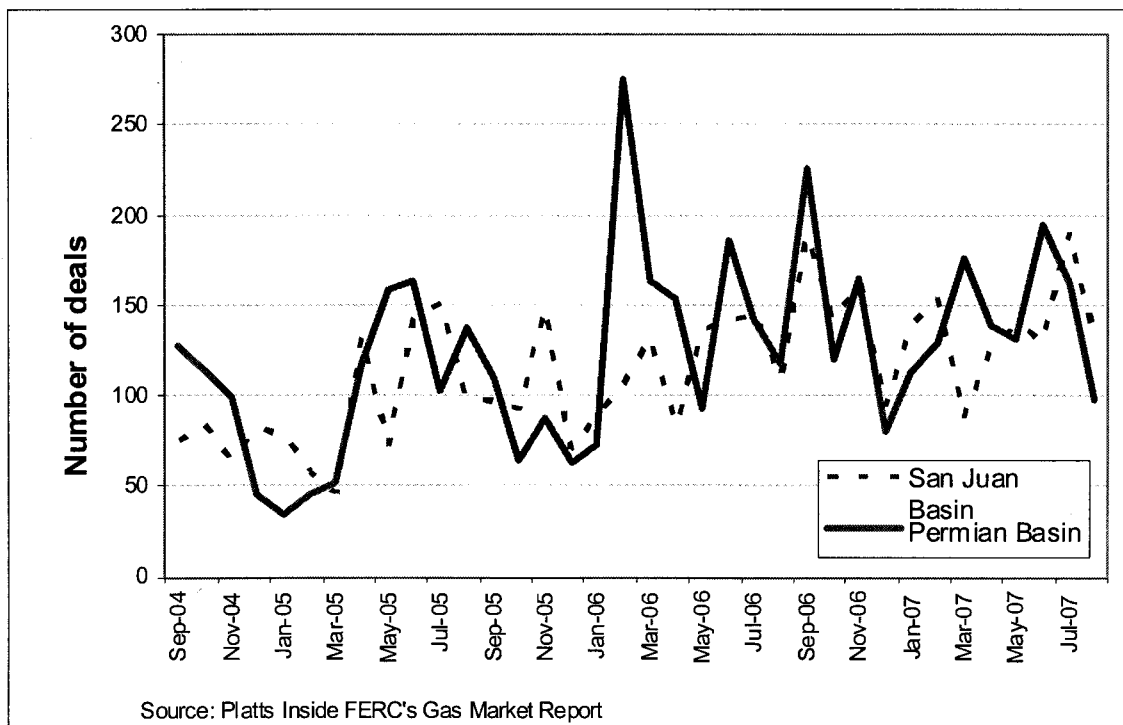


Exhibit 3-13. Number Of Deals Included In Published FOM Indices



Platt's Inside FERC Gas Market Report and *Gas Daily* are bellwether industry publications and many U.S. physical transactions are based upon them. The cash indices mentioned above, as well as most U.S. natural gas cash pricing, are to some degree influenced by NYMEX prices, regardless of whether one is directly participating in NYMEX markets or not. The starting point for virtually all U.S. gas pricing is the NYMEX Henry Hub delivery location (and all related look-a-like OTC markets such as ICE).⁸ Virtually all U.S. prices are composed of NYMEX Henry Hub, plus or minus a basis price differential. Forward price curves are built off this concept as well. Because of this phenomenon, market participants constantly watch changes in the NYMEX Henry Hub values which tend to inform and influence their decisions about the market fundamentals and the general state of participation by the different types of market participants (for instance, speculators versus hedgers).

SW Gas' internal policies allow it to transact fixed priced gas at either one single value or in two separate components, NYMEX and basis to be locked at different times. EVA's opinion is that because the NYMEX component is already embedded (directly and indirectly) into a company's gas purchases, it is sometimes best to assert control over that pricing component if trying to meet a specific objective, rather than to be at the whim of market forces. Stated in other words, EVA is not concerned that SW Gas may rely on NYMEX based pricing, as this is the leading price benchmark of the U.S. industry, and it cannot be avoided. NYMEX prices indirectly influence all gas prices, thus having the option of control over it, is preferable, to having no control.

Manipulation of U.S. published gas market price indices and manipulation of gas markets has been under intense scrutiny, particularly from activities of 2000 through 2006. Some of the more notable cases have involved companies such as Amaranth and El Paso Energy. The relevant contracts involved some of the most liquid price indices in the natural gas industry, including NYMEX and ICE contracts based on a liquid Henry Hub reference delivery point. While such events may be characterized as unfortunate, the silver lining, if any, is that today there is greater market oversight and enforcement of the natural gas markets by both the FERC and the CFTC. It is EVA's belief that this stepped up enforcement will help to minimize potential future abuse of natural gas

⁸ Intercontinental Exchange

markets and pricing indices. Many gas utilities and other industry participants are price takers and need to rely on published indices as representations of competitive commodity markets. It is in the best interest of all participants for all pricing points to have reliable and valid published price indices.

In reality, any of the published price indices can be subject to potential abuse if an individual, or set of individuals, are intent on pursuing an unfair advantage in the marketplace. Theoretically, higher liquidity (greater number of transactions reported, higher volume coverage, and participation by a larger number of companies), helps protect price indices against potential market manipulation. An annual review by SW Gas of its counterparties may indirectly help to address some of this concern, along with monitoring of and vigilance over the liquidity of the price indices it uses.

A final and controversial subject is the potential requirement to report transactions and deal information to industry publications for inclusion in published price indexes. As stated previously, EVA believes that is to the benefit of all market participants (including utility rate payers) to have reliable and valid published indices based on truly competitive market forces. To EVA's knowledge, SW Gas currently does not report pricing information to industry publications. Contributing their specific company information would increase liquidity for the indices that concern SW Gas and be likely to have the impact of increasing the reliability of the published indices. The desired ideal standard is for all companies to participate to create a highly competitive marketplace.

However EVA also strongly feels that each company must be responsible to determine its own comfort level and ascertain its risks and rewards before participating in the sharing of its confidential information. Participation is not a trivial matter in today's litigious world.

If SW Gas decided to participate, it would need to ensure that its associated processes were sufficiently well-designed to the minimize risks associated with this process. One of the recommended requirements would be to create complete independence between the personnel and functions that report deals to publications from the personnel and functions that procure gas. For instance reporting could be done from the Accounting Department or Risk Management Department. It should be noted there is an associated

administrative burden and cost to such reporting. Southwest's current *Code of Business Conduct & Ethics* require that "media inquiries must be referred to the Corporate or Division Communications Departments." There is also a potential conflict of interest if any 'trading' occurs inside a utility procurement shop, which is not the case for SW Gas. Likewise if gas buyers' bonuses are based on beating published indices (and buyers are responsible to also report data to publications), incentives to 'distort' reality could exist. All of the positions in Southwest's gas purchasing and transportation department were reported as 'salary only' positions.⁹

There are other complexities to consider on this topic. For instance, the 50% of so of the total volume that Southwest purchases for the APSP program does not have a natural publication to report into, since these are purchases made in the forward markets, out one to two years in the future, and are classified as over-the-counter deals that are more illiquid the farther one goes into the future. The trade publications discussed above tend to focus on next month (bid week) and next day (daily) markets. The most popular electronic venue that reports the more illiquid over-the-counter deals is the ICE. SW Gas participates on the ICE, particularly for its spot gas purchases for next day and next month. The ICE has the benefit of increasing workplace efficiency regarding price discovery and facilitating quick execution of transactions, with high liquidity for the short term markets. It is an essential tool for today's gas buyers. One primary question is whether SW Gas would report 100% of its transactions, or only those transactions that have relevance to the daily and monthly index publications.

If the ACC decided to require Arizona regulated gas utilities to participate in the reporting of transaction data to publications, for fairness reasons and to level the playing field, it would be important to also require regulated electric utilities to report as well. Unilaterally ordering gas utilities to report could be discriminatory. Any decision by the ACC to report could also have unintended consequences, and thus would need to be carefully examined before mandating participation.

Policies And Procedures

EVA found that many of SW Gas company policies, procedures, and strategies are insufficiently documented in official company documents. While the concepts embedded

⁹ EVA email discussions with senior management of Southwest Gas dated March 4, 2007.

in SW Gas' policies, procedures, and strategies appear reasonable and prudent, curiously one must tend to go to the documents submitted by SW Gas to the Arizona Corporation Commission to find the most complete picture of company policies, procedures, and strategies. In addition, some policies, procedures, and strategies fall short in certain areas by their lack of documented official position on certain subjects.

Best Practices require that policies and procedures are contained in, say, one or two company documents with sufficient detail such that new employees could read and immediately perform the bulk of their work. The *Annual Gas Procurement Plan (Section A)* submitted in December of each year to the ACC is probably the most comprehensive discussion of Southwest's gas supply policy, outside of external consultant's reports.¹⁰ However, only *one* paragraph (the first paragraph) discusses SW Gas' supply strategy. The remainder of the Section A (another 4.5 pages) discusses SW Gas' acquisition procedures. Another good discussion of Southwest procedures is found in *Department and Staff Responsibilities, Portfolio Selection Procedures*¹¹ originally created for submission to the ACC. While containing valuable information, these documents still fall short in several areas as noted under the recommendations. These recommendations take on elevated importance and urgency given SW Gas's expected execution of its first-ever financial derivative hedge in 2008. (It should be noted that EVA did not review any of the policies and procedures associated with financial derivative hedging.)

EVA recommends that Southwest clarify all company policies and procedures in internal company documents to be reviewed, at least annually, for use by both employees and decision makers. Company employees should acknowledge acceptance by signing the policies each year. EVA's recommendation is to supplement current policies and include discussion on the following types of topics:

1. Consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.
2. Clarify the APSP supply element by documenting required timing and volumes for the next one or two years forward. This is important because these are long-term fixed price purchases that have repercussions to the gas supply portfolio for several years. The 2007 Arizona Annual Gas Procurement Plan submitted to the

¹⁰ 2004 through 2007 versions were reviewed

¹¹ Docket No. G-01551A-07-0504, Data Request STF 4.25.

ACC contains the most detail description of the APSP such that "Southwest conducts solicitations from November through August every three to six weeks" ... "for the upcoming portfolio year and up to one year beyond that year" ... "and may include bid requests for one or more of the three portfolio years." Senior management noted that this element was intended to be "programmatic," yet there is no calendar showing potential dates or quantities to be purchased in the year or quarter ahead. Verbally Southwest explained that its intention was to purchase about 40% of the next year's supply in the twelve months preceding physical flow, and another 10% in the two years preceding physical flow for a total of about 50%. That would be about 2% to 5% in each transaction, with some 4 transactions during the thirteen to twenty-four months before physical flow and another 10 purchases made during the last 12 months before physical flow. Truly successful dollar cost averaging relies on programmatic dates and volumes that are known and planned. Some companies have found the use of living appendices (to the annual company policies) helpful to update forward time windows and volume ranges that may change frequently. If there is uncertainty, then windows of time and ranges of volume or duration can be established instead. This approach also has the benefit of allowing a record of results and allows documentation of reasons for any deviation from the plan which in the long run improves the quality of the internal and external audit trail(s) and makes it easier for a company to assert and prove that their hedging programs have been prudent.

3. During the onsite interviews of mid-January 2008, it was noted that lately much of the APSP gas was entirely fixed at the time of initial purchase, that is, no price components were left floating to be locked-down at a later date. SW Gas policies allow management to use their judgment on this issue. EVA agrees that this preference is best left to the judgment of SW Gas management and their experts. Still EVA has several comments about this topic.
 - a) If SW Gas uses its best judgment, to be certain, there will be outcomes that "win" some years and other outcomes that "lose" in other years. One's best judgment is not always correct, and thus, should not be expected to always be correct.
 - b) A truly programmatic hedge involves always being a price taker (without reserving judgment) over a relatively long stretch of time that allows dollar cost averaging to occur effectively.
 - c) A hybrid of the two above strategies is acceptable, but the precise strategy should be recognized and declared in company policies and procedures to guide employees and decision makers, as well as the ACC's oversight.
4. On a daily basis, transactions executed by Southwest gas buyers bind the company as they purchase gas from various suppliers. During interviews, Southwest management explained that prior to each flow month, the Supply Planning Department provides gas buyers with a monthly plan, *Arizona Dispatch Guidelines*, that outlines all firm purchase contracts sorted in order of economic dispatch to be utilized for the upcoming flow month. These documents were viewed by EVA. In EVA's view, this document basically acts as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement.

It is a sound process, however no mention of this document or process was found in any company policy or procedure. This process should be included in the description of the buyers' formal procedures.

5. During interviews, it was noted out that SW Gas has a company policy of never selling excess gas to third parties, for various regulatory and legal reasons that have roots in both FERC, as well as FAS, regulations due to potential negative repercussions as perceived by the company. However it is impossible for any LDC to perfectly predict load for each day and every hour. Additionally since SW Gas has no storage capacity to flow its excess gas and because it potentially faces high El Paso Pipeline charges and/or penalties for pipeline imbalances, SW Gas needs to have an internal mechanism to balance its occasional excess gas. SW Gas uses the concept of 'unbuying' to help optimize its portfolio and minimize cost. In such circumstances, a SW Gas buyer instructs the original supplier of the gas not to deliver gas that it had previously purchased, and to charge SW Gas accordingly. Such 'unbuying' transactions, or turning back of gas, then lead to liquidated damages per contract terms (some true-up or true-down to current market between SW Gas and the supplier) and possibly a small additional or negotiated charge. 'Un-buying' practices may have accounting repercussions where SW Gas must mark-to-market any 'un-bought' gas if it was originally based on firm fixed priced contracts. For this reason, SW Gas has a policy of turning back index priced gas first, and second turning back fixed priced gas, if necessary. These company policies, as well as the reasons for the policies, should be reevaluated, and then explicitly documented in official company policies and procedures.

Comparison Of Monthly Bank Balance Statements And GTS

For gas commodity charges, a comparison was made between all GTS transactions and the Monthly Bank Balance Statements filed with the ACC. Exhibit 3-14 tabulates the differences for monthly volumes and values. The monthly difference is expressed as Monthly Bank Balance Statement minus the GTS transactional values. The differences can be attributed to items that are not captured in the GTS system: (a) liquidated damages per contract terms, (b) commodity demand charges, (c) balancing cash-outs to/from El Paso Natural Gas Pipeline, (d) gas related to Dacott Industries that delivers on Transwestern, and (e) prior period corrections. A positive difference is read such that SW Gas must pay this additional amount over and above the gas commodity charges captured in the GTS system. A negative difference is a credit.

Exhibit 3-14 Difference Of Monthly Bank Balance Statements Minus GTS Data

	Value	Volume (mmBtu)
Sep-04 \$	12,311	3,433
Oct-04 \$	21,201	4,481
Nov-04 \$	149,709	6,080
Dec-04 \$	146,898	9,633
Jan-05 \$	238,599	9,032
Feb-05 \$	204,543	10,977
Mar-05 \$	255,029	3,365
Apr-05 \$	14,907	2,322
May-05 \$	95,130	1,881
Jun-05 \$	9,073	1,530
Jul-05 \$	7,370	1,467
Aug-05 \$	8,146	1,434
Sep-05 \$	12,976	1,487
Oct-05 \$	45,619	1,848
Nov-05 \$	84,834	3,572
Dec-05 \$	157,205	6,743
Jan-06 \$	166,271	6,290
Feb-06 \$	135,552	4,071
Mar-06 \$	86,944	3,738
Apr-06 \$	74,032	12,563
May-06 \$	9,196	1,803
Jun-06 \$	7,993	1,472
Jul-06 \$	7,104	1,469
Aug-06 \$	21,395	3,201
Sep-06 \$	14,459	3,286
Oct-06 \$	12,474	2,485
Nov-06 \$	234,459	20,822
Dec-06 \$	191,000	6,655
Jan-07 \$	2,036,644	229,081
Feb-07 \$	161,415	4,041
Mar-07 \$	176,385	(1,280)
Apr-07 \$	13,066	2,275

EVA evaluated these differences for reasonableness.¹² Only the differences for January 2007 appeared somewhat extraordinary representing 1.9% of GTS volumes and 2.3% of GTS values. As previously noted, heating degree days for Phoenix during January 2007 were 13% above normal. Southwest's purchased gas expenses were the largest of the audit period for January 2007 at \$90.2 million for load of 12,368,219 mmBtu.

Further analysis of January 2007 showed that 97% of the total volume was due to item (c) above, balancing cash-outs payments made to EPNG. For January 2007, Southwest was forced to pay El Paso 221,845 mmBtu, or \$1.85 million, to bring the gas commodity imbalance down to 5%. EPNG requires monthly imbalances in excess of 5% to be

¹² Of the 32 months, difference was 0.1% for 27 months and 0.2%-0.4% for four months.

cash-out and reduced to the 5% level in the first month of the imbalance, with the remainder rolled forward to the second month when EPNG requires that the imbalance is reduced to 3%, and finally reduced to 0% in the third month of its existence. Each month is tracked separately by EPNG, and prior and next months are not rolled into administration of each current month's requirement.

If load was forecasted correctly, SW Gas would still have had to purchase this gas from a third party supplier. Instead SW Gas was forced to purchase this gas from El Paso, which did charge a premium over market. The average price paid to El Paso is estimated by EVA at \$8.327/mmBtu, compared to the highest Daily or First of Month published market index of \$6.42 (Daily Waha), calculating to a premium of some \$423,054 to bring the imbalance down to 5%.

Several factors should prevent this situation from occurring again. A repeat of such a large cash-out penalty in the future might be very well be viewed as imprudent given SW Gas' climb up the learning curve since the introduction and implementation of El Paso's new tariffs during 2006 and 2007. EVA would expect the following (and subsequent) items to prevent a repeat of such a large cash-out from occurring, particularly:

- a) Proactive improvements to the quality and accuracy of SW Gas' load forecasts.
- b) Changes to treatment of SW Gas T-1 customers.
 - o Changes to SW Gas's tariff that now allow pass-through of EPNG charges to T-1 customers, if caused by T-1 customers.
 - o Addition of Firefly meters to SW Gas T-1 customers.
 - o Implementation of EVA recommendations to tighten controls around T-1 customers to monitor existence of their proper and independent supply contracts (per EVA recommendation in Chapter 2).
- c) Changes to El Paso's tariff that subsequently calculated the required monthly cash-out compared to the month's total scheduled volumes on all transportation contracts, versus formerly calculating the cash-out compared to volumes scheduled only on the "NAESB Swing" designated transportation contracts. FERC approved of this all-party settlement in January 2007 but did not approve the change until March 2007. SW Gas' January 2007 imbalance would have only totaled to about 3% instead of 13% if FERC approval was implemented for January 2007.¹³

¹³ Various email discussions between EVA and SWG dated March 3rd through March 6.

In addition to the above as opportunities arise, EVA recommends that SW Gas continue to press EPNG to improve its quality of 'real time' load estimates that it broadcasts to shippers via EPNG's Electronic Bulletin Board.

Audit Of Selected Transactions

EVA analyzed whether SW Gas followed its policies and procedures based on an audit of selected transactions.¹⁴ EVA believes that overall SW Gas did a good job of following its policies and procedures. EVA's management recommendations for improvement are:

1. Ensure all confirmations with gas suppliers, also known as Exhibit A, include deal transaction dates. Many inadvertently noted the transaction date at the top of the confirmation as the first physical flow date instead of the actual deal date.
2. Ensure all confirmations with suppliers, also known as Exhibit A, include dates of the internal approval next to authorized signature. The VP of Gas Procurement's signature was sometimes present without the date of authorization.
3. Considerably shorten the time lapsed between deal execution and deal confirmation with gas supplier. Some of the audited transactions show lapses of up to three and four months between execution and confirmation, with one and two months for many others. This lapse should probably be no more than one-two weeks at the very most; two to three days would be best. (This will become particularly important for financial derivative transactions where markets can move very quickly.)
4. Include a list of attendees present during the solicitation and purchase of APSP fixed price gas (and during the selection of the index, or term gas, packages) to ensure independence, proper monitoring, and to improve the audit trail. The solicitation information received by EVA for the APSP packages did not include this documentation.
5. Update any old master supply agreements that cap the buyers' liquidated damages at 50 cents per mmBtu to agreements that are based on true-up to actual market during non-performance. Several agreements examined retained the 50 cent cap.

The audit was designed in four parts as described below and focused on the 2006/2007 winter months:

- a) For the Arizona Price Stability Purchases, five solicitation packages were reviewed including all competing bids, notations, forward price curves, signed master contracts, signed confirmations, settlement statements, and the tally of supply acquired to date for the APSP. (Onsite Data Request 9)

¹⁴ This particular audit is addressed by EVA Onsite Data Requests 6, 7, 8, and 9.

- b) For the index, or term, supply element, Planning Department logs were examined that included all of the supplier offers (aka "bids" in SW Gas parlance) received for the 2006/2007 winter months (November-March). Also EVA examined several early and the final runs of the Evaluation Reports that optimized the total universe of supplier offers. (Onsite Data Request 8)
- c) For the index, or term, supply element, six supplier packages were reviewed that represented successful bids consummated by SW Gas including signed master agreements, signed confirmations, and settlement statements. These contracts were also tied back to the Planning Department's selection of optimized contracts. (Onsite Data Request 7)
- d) EVA reviewed the *Arizona Dispatch Guidelines* used by the gas buyers for the months of December 2006 and January 2007. The APSP baseload and index contracts reviewed and discussed above were also noted for inclusion in these guidelines. (Onsite Data Request 6)

The actual supplier contracts reviewed above were selected based on a variety of suppliers, a variety of contract durations, a variety of pricing indices, and a variety of dates that agreements were entered into within the general structure designed by EVA above.

Appendix

Exhibit A-1. El Paso Natural Gas Penalty Matrix

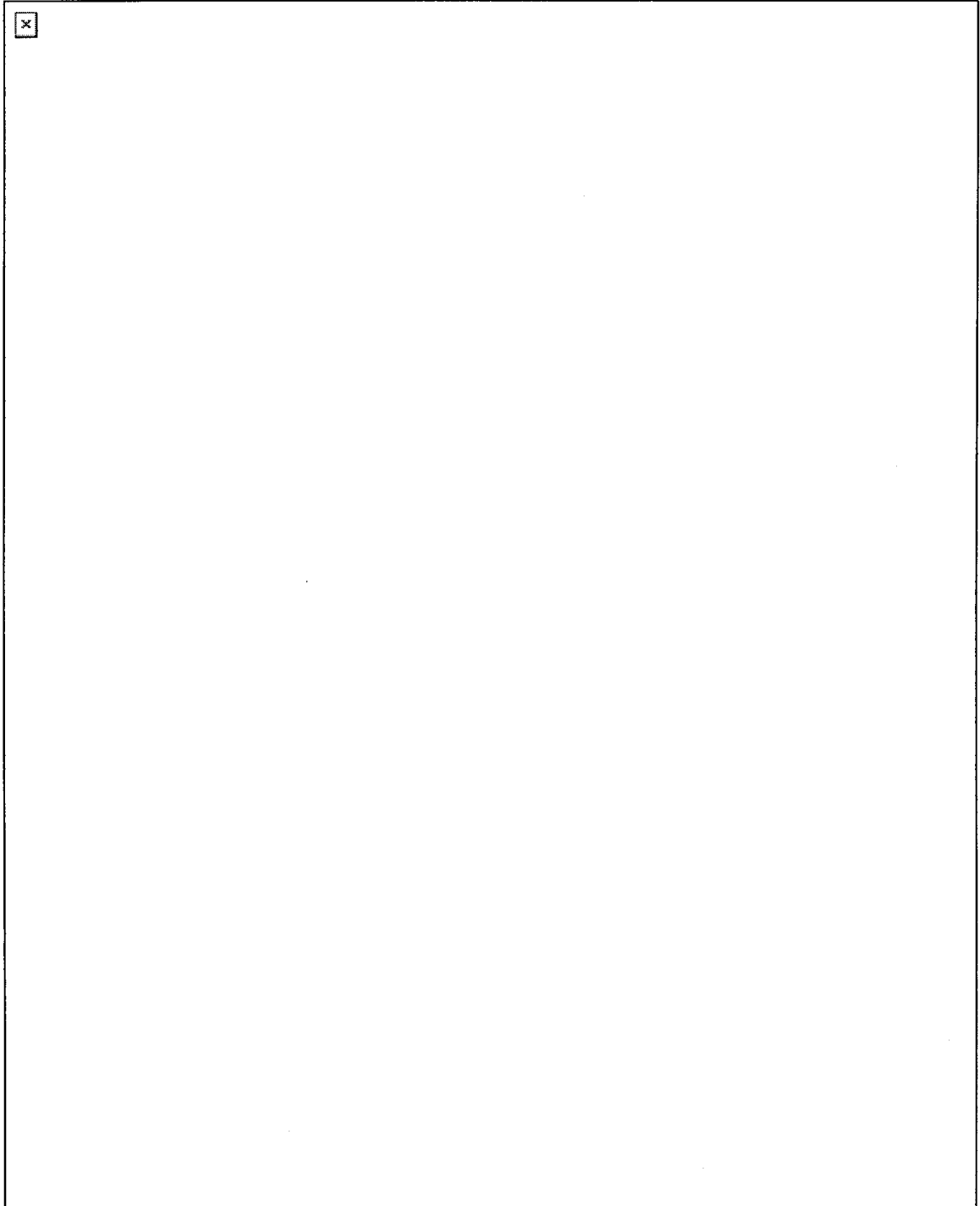


Exhibit A-1. El Paso Natural Gas Penalty Matrix

7	COC (Critical Operating Condition) Imbalance Charge	COC is issued when Operating Conditions continue to threaten the integrity of the pipeline. EPNG may issue COC.	Threshold is 3% of scheduled quantity* at the delivery point under the TSA or 2,000 dth, whichever is greater.	Not applicable	During COC, Daily Imbalance Charges for the first day of the COC will be assessed to any Shipper in the COG area with a daily imbalance that exceeds the threshold of 3% of scheduled quantities. No catch-up nomination allowed during COC.	During a COC, charges equal to the higher of \$10 per dth or two times the highest daily mid-point spot price reported. Shippers should monitor scheduled vs. operational flows under Flowing Gas, SOC/COC.	On a day, a Shipper will be charged the higher of: 1) Hourly Scheduling Penalty; 2) Daily Unauthorized Overrun; 3) MDO/MHO Violation (if Operator and Shipper are the same party); or 4) SOC/COC imbalance penalties.
8	Emergency COC Imbalance Charge	Emergency COC is issued when Operating Conditions continue to threaten the integrity of the pipeline. SOC does not have to be called first.	Threshold is 3% of scheduled quantity* at the delivery point under the TSA or 2,000 dth, whichever is greater.	Not applicable	During COC, Daily Imbalance Charges for the first day of the COC will be assessed to any Shipper in the COG area with a daily imbalance that exceeds the threshold of 3% of scheduled quantities. For any subsequent day(s) of an Emergency COC, no threshold.	During a COC, charges equal to the higher of \$10 per dth or two times the highest daily mid-point spot price reported. Shippers should monitor scheduled vs. operational flows under Flowing Gas, SOC/COC.	On a day, a Shipper will be charged the higher of: 1) Hourly Scheduling Penalty; 2) Daily Unauthorized Overrun; 3) MDO/MHO Violation (if Operator and Shipper are the same party); or 4) SOC/COC imbalance penalties.
* For Swing locations, includes all scheduled quantities at the locations where the contract is swing effective with Settlement							

The map displays the state of Arizona with its major highways and cities. The following power plants are identified on the map:

- South Point 530 MW
- West Phoenix 650 MW
- Harquahala Valley 1,048 MW
- Redhawk 1,060 MW
- Gila River 2,145 MW
- Mesquite 1,250 MW
- Kyrre 250 MW
- San Carlos 825 MW
- Arlington Valley 570 MW
- Sundance 450 MW
- Desert Basin 529 MW
- North Loop 23 MW
- Demoss Petrie 72 MW
- Saguaro 380 MW
- Apache Peaker 40 MW
- University of AZ Cogen 6 MW

Exhibit A-3. Chronology For 2005 El Paso Natural Gas Rate Case

Docket No. RP04-251 Regarding Segmenting, Pathing, OFOs, and Strained and Critical Condition Provisions

Dec 20, 2004 – The FERC issued Order of settlement in Docket No.04-251 which among other things established Strained and Critical Operating conditions daily pack and draft penalties to become effective 1/1/06.

Docket No. RP05-422 General Rate Case Including New Services and Penalties for Improper Use of the System

June 30, 2005 – El Paso filed a rate case proposing new rates, new services and new penalties presuming that effectiveness would be suspended until 1/1/06. The proposal included MDO/MHO violation penalties, hourly scheduling penalties, hourly interruptible swing charges, non critical daily scheduling pack and draft penalties, and daily over-run charges. That filing proposed a modification to the 11.2 rate protections from the 1995 rate case.

July 29, 2005 – The Commission issued an order accepting and suspending El Paso's primary tariff sheets, subject to conditions and the outcome of a hearing (on rate issues) and a technical conference (for non rate issues i.e., penalties and new services).

October 3, 2005 – EPNG submitted a filing which among other things detailed the distribution of firm capacity (MDQ) to each meter within a D-Code for EOC shippers that were receiving parties.

October 4, 2005 – EPNG filed Offer of Partial Settlement with FERC that deferred EPNG implementing proposed new services including Rate Schedule OPAS (MDOs/MHOs) as well as new penalties and new default service charges until April 1, 2006.

December 2005 – EPNG conducted an open season for an MDQ Adjustment Request process by which shippers were able to request a shifting of MDQs between meters and D-Codes.

December 12, 2005 - FERC approved the Partial Settlement (October 4, 2005 filing) and directed EPNG to file the deferred tariff sheets and provisions 30 days prior to April 1, 2006.

January 1, 2006 The filed rates went into effect subject to refund.

February 16, 2006 – EPNG filed with FERC the results of the December 2005 MDQ Adjustment process.

Exhibit A-3. Chronology For 2005 El Paso Natural Gas Rate Case

March 20, 2006 – FERC issued an Order in response to briefs filed by many parties which addressed Article 11.2 rate issues. In short it preserved the 11.2 rates and provisions under certain conditions but provided that if a customer converts 11.2 a protected FT-1 service to a premium service then the 11.2 a protection would not apply.

March 23, 2006 – FERC issued an Order, regarding issues that were addressed in the Technical Conference process (non rate issues), that accepted El Paso's proposed hourly scheduling penalties but rejected El Paso's proposed non-critical daily pack and draft penalties. El Paso interpreted FERC's Order as approving a daily scheduling "pack penalty".

March 29, 2006 – EPNG requested proposed turn back capacity from interested shippers. Also on March 29, 2006, EPNG filed an "Offer of Settlement" conditionally waiving the implementation of certain provisions of the New Services and charges (penalties) from the effective date of the applicable tariff provisions on April 1, 2006 until June 1, 2006, to provide more time for parties to prepare for the implementation of New Services.

April 18, 2006 – Southwest submitted its request for New Services from El Paso submitted in response to El Paso's Contract Reformation Guidelines. Southwest's premium service contracts went into effect November 1, 2006.

May 16 – May 31, 2006 – EPNG conducted an MDO Open Season for shippers to solicit increased MDOs.

May 31, 2006 – The FERC issued an order rejecting El Paso's compliance filing.

July 24, 2006 – EPNG filed a "MDO Report" with FERC (and on July 31, 2008 filed an update) that detailed the results of the MDO open season, detailing the MDOs to become effective August 1, 2006.

August 1, 2006 – OPASA was executed with MDO quantities filed with FERC in the "Update MDO Report". Since this OPASA, Southwest has submitted to El Paso numerous MDO adjustment requests for incremental MDO at numerous metering points.

December 06, 2006 – EPNG filed offer of settlement supported by all but one party. Articles 6., 7., and 9. deal with penalties, default service charges and credits.

August 31, 2007- FERC approved the Settlement.

Docket No. RP06-368

May 24, 2006 – El Paso filed a waiver request of MDO/MHO violation penalties in non-COCs from 6/1/06 to 7/31/06.

Exhibit A-3. Chronology For 2005 El Paso Natural Gas Rate Case

Docket No. RP06-392

June 13, 2006 El Paso filed a waiver request of hourly scheduling penalty (Critical and non-Critical), hourly authorized and unauthorized overruns, daily variance charges; Rates for FTH and NNTH were discounted to max FT-1 rate; IHSW charges were waived 6/1/06 through 7/12/06 (initially). Extended through 6/6/06.

July 10, 2006 El Paso filed supplement to the waiver, Rates for NNTD were discounted to max FT-1 rate 6/1/06 – 7/12/06.

Docket No RP06-431

July 11, 2006 - El Paso filed a request to waive hourly scheduling penalties (Critical and non-Critical) and hourly authorized and unauthorized overruns daily variance charges and IHSW service charges during 7/13/06 – 7/31/06; For 8/1/06 – 8/31/06, to waive hourly scheduling penalties (Critical and non-Critical) and hourly authorized and unauthorized overruns at delivery locations where Shippers used IHSW service; Continue to waive MHO violation penalties through 8/31/096; HEEN not included in daily-unauthorized overrun calculation; Extension of scheduling accounts through 8/31/06; No cash-out down to 5% for June imbalances.

August 31, 2006 - El Paso filed a request to waive daily variance charge, MDO violation penalty, MHO violation penalty, hourly scheduling penalty (Critical and non- Critical); August requirement that a shipper have IHSW to receive waiver of hourly scheduling penalties no longer applies; Continue use of scheduling accounts.

September 29, 2006 - El Paso filed waiver of tariff provision in order to continue use of scheduling accounts through 1/31/07.

Docket No. RP07-108

December 13, 2007 - El Paso filed a request to waive daily variance charges for shippers who packed the system, thereby helping to mitigate the Critical Condition (daily Variance charges deemed to be zero for the "higher-of-test"); Contract and service related penalties (i.e. daily and hourly Unauthorized overruns, hourly scheduling penalties, MHO/MDO Violation penalties) billed at the non-Critical rate for all shippers.